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Advanced Technologies for Power/Industrial Applications

WABASH RIVER PROJECT MOVES INTO COMMERCIAL OPERATION

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ABSTRACT

The Wabash River Coal Gasification Repowering Project, selected by the United States Department of Energy as a Clean Coal IV demonstration project in September 1991, is in startup and is expected to begin commercial operations in August of 1995. The Wabash Project is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, which will repower an existing 1950's vintage coal-fired steam-powered generating unit with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station and will process locally-mined Indiana high-sulfur coal to produce 262 megawatts (net) of electricity. When the project begins commercial operations, it will represent the world's largest single-train coal gasification combined cycle power plant to operate in a fully commercial setting. In addition, it will emit lower emissions than other high sulfur coal fired power plants, improves the heat rate of the repowered unit by approximately twenty percent, and will produce some of the lowest cost electricity on the PSI system. The Project is ready to demonstrate, on a commercial scale and in a commercial utility environment, that coal gasification combined cycle technology can be used to meet domestic and global energy and environmental needs.

This paper will summarize the Wabash Project's contributions toward advancing the commercialization of integrated coal gasification combined cycle technology.

INTRODUCTION

Barriers to Commercialization

The electric utility industry has traditionally been reluctant to implement new technologies because of insufficient mechanisms for balancing the risk/return tradeoff associated with new technology. Their rate of return on new technology is regulated at the same level as established (lower risk) technology. New technology investments which do not immediately meet performance expectations may even be disallowed from their rate-base. Utilities simply lack incentive to invest in or develop new technologies.

Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy projects are for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

The Commercial Significance of the Wabash Project

There exists a remarkably high degree of alignment between the Project, the DOE, and the Participants with respect to the objective of advancing the commercialization of coal gasification technology. In view of the Project's pre-operational status, however, what's truly striking is it's impact thus far in terms of abating the barriers described above and otherwise advancing commercialization.

Even at this intermediate stage of the Project, many parties have participated in (or are the beneficiary of) aspects of the Project which constitute commercial advances, including the coal industry, the financial community, regulators, permitting agencies, the unions and their craft labor, and technical support industries, not to mention the DOE and the Participants themselves.

The intent of this paper is to communicate the Project's prominent success stories and related elements which represent substantive advancements in the commercialization of CGCC technology.

OVERVIEW

The Wabash River Coal Gasification Repowering Project (the Project), conceived in October of 1990 and selected by the United States Department of Energy as a Clean Coal IV demonstration project in September 1991, is in startup and is expected to begin commercial operations in August of 1995.

The Participants, Destec Energy, Inc., (Destec) of Houston, Texas and PSI Energy, Inc., (PSI) of Plainfield, Indiana, formed the Wabash River Coal Gasification Repowering Project Joint Venture (the JV) to participate in the DOE's Clean Coal Technology (CCT) program and demonstrate the coal gasification repowering of an existing generating unit affected by the Clean Air Act. The Participants, acting through the JV, signed a Cooperative Agreement with the DOE in July 1992.

The Participants jointly developed, and separately designed, constructed, own, and will operate an integrated coal gasification combined cycle (CGCC) power plant wherein Destec's coal gasification technology is used to repower one of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The Project demonstrates the integration of Destec's gasification process with a new GE 7FA combustion turbine generator and heat recovery steam generator in the repowering of a 1950's-vintage steam turbine generator using pre-existing coal handling facilities, interconnects, and other auxiliaries.

The Project will convey substantial benefits to PSI and its customers. It will process locally-mined Indiana high-sulfur coal to produce 262MW (net) of clean, low-cost, energy efficient baseload capacity. The Project is anticipated to function as a substantial element of PSI's plan to comply with the Clean Air Act because, with SO_2 emissions at less than .02lb/MMBtu of fuel, it exceeds the Phase II requirements of those regulations. CINergy, PSI's post-merger organization, plans to dispatch the Project second behind their hydro facilities on the basis of both environmental emissions and efficiency because the facility has a net plant heat rate of approximately 9,000 BTU/kWh (HHV) and the ability to produce some of the lowest cost electricity on their system. The facility is expected to operate as part of CINergy's baseload capacity for a period of at least 25 years, the first three years of which function as the Demonstration Period under the DOE CCT program.

When the Project moves into commercial operation, it will represent the world's largest single-train coal gasification combined cycle power plant to be operated in a fully commercial setting. In addition, the Project will have lower emissions than other high sulfur coal fired power plants, will improve the heat rate of the repowered unit by approximately twenty percent, and will have the lowest capital cost in terms of $/KW of all past and current CGCC demonstration Plants. The Project demonstrates, *on a commercial scale and in a commercial utility environment*, that CGCC technology can effectively meet domestic and global energy and environmental needs.

BACKGROUND

Historical Perspective of Project Development

Development of Destec's Coal Gasification process was begun in the early 1970's by the Dow Chemical Company, Destec's parent company, in order to diversify their fuel base from natural gas to lignite and other coal. The technology at Wabash represents an extension of the collective experience gained through basic R&D, several pilot plants, and the Louisiana Gasification Technology, Inc. (LGTI) facility in Plaquemine, Louisiana. LGTI is a 160MW coal gasification facility which has been operating since April 1987. The engineering and design of Wabash completed the transfer of coal gasification engineering expertise from Dow to Destec.

Encouraged by the data and experience gained at LGTI and by the DOE CCT program, Destec approached PSI in early 1990 to initiate discussions concerning the Wabash Project. Destec and PSI subsequently formed the JV to participate in Round IV of the DOE CCT Program. In September 1991, the Project was among nine projects selected from 33 proposals submitted during Round IV. The Project was selected to demonstrate the integration of Destec's gasification process with a new GE 7FA combustion turbine generator and HRSG in the repowering of an aged steam turbine generator to achieve improved efficiency and reduced emissions. In July 1992, the JV signed a Cooperative Agreement with the DOE under which the JV developed, constructed, and will operate the subject coal gasification combined cycle (CGCC) facility, with the U.S. DOE providing up to $219 million of cost-share funding for construction and a three year Demonstration Period.

Goals of Participants

The goals of the Participants in developing this project centered around three main themes:

- PSI wanted a proven, alternative technology for the future repowering of existing units and for new units.
- Destec wanted to enhance the competitive position of an improved technology by demonstrating new techniques and process enhancements as well as substantiate performance expectations and gain information about capital and operating costs.
- The DOE wanted to abate the barriers to commercializing clean coal technologies, particularly gasification and repowering applications, and otherwise enable utilities to make informed commercial decisions concerning the utilization of clean coal technology.

As the Participants prepare to enter commercial operations, their goals revolve around four fundamental objectives:

- PSI seeks to incorporate the subject IGCC power plant into their system as a reliable and cost-effective element of their baseload generation capability;
- Destec seeks to demonstrate the operability, cost-effectiveness, and economic viability of their technology on a commercial scale and in a commercial utility environment;
- Together, PSI and Destec seek to optimize the cost-effectiveness of system elements, of operating, maintenance, and management disciplines, and of the overall system, and otherwise advance the technology itself;
- Destec and the DOE seek to obtain the data base and experience-base necessary to advance and meet the commercial markets for this technology.

Project Organization and Commercial Structure

In general, Destec is responsible for financing, constructing, and operating the gasification island, and PSI is responsible for financing, constructing, and operating the power block. Two agreements establish the basis for the relationship between PSI and Destec. The Joint Venture

Agreement created the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the Project under the DOE Cooperative Agreement. The Gasification Services Agreement (the GSA) contains the commercial terms between PSI and Destec under which the Project will be developed and operated. The structure of the GSA allowed the Project to be integrated for high efficiency and provided for the use of common facilities to eliminate duplication. The major provisions of these agreements include:

PSI Responsibilities:

- to build the power generation facility to an agreed common schedule
- to own and operate the power generation facility
- furnish Destec with a site, coal, electric power, stormwater and wastewater facilities, and other utilities and services
- pay a monthly fee to Destec for gasification services

Destec Responsibilities:

- to build gasification facility to an agreed common schedule
- own and operate the coal gasification facility
- guarantee operating and environmental performance of the coal gasification facility
- deliver syngas and steam to the power generation facility.

Project Cost and Efficiency

Integrating the new/existing power generation facilities with the new gasification facility have resulted in a lower installed cost and higher efficiency than other "environmentally equivalent" coal based power generating projects. Reduced development effort and a shorter schedule have also resulted from choosing to repower an existing station rather than developing a greenfield installation. This advantage is evidenced by the rapid development and construction progress described elsewhere in this paper.

The combined net plant heat rate is expected to be approximately 9000 Btu/kWh, an improvement of nearly 20 percent over the pre-existing unit. Since performance guarantees for major equipment items (Combustion Turbine, HRSG, HTHRU, *etc.*) contain the manufacturer's margin, and these guarantees are imbedded in this energy balance calculation, actual operation is expected to be slightly better. With a heat rate among the lowest of commercially operated coal-fired facilities in the United States, the Project is expected to produce some of the lowest cost electricity on the PSI system.

Repowering the existing unit, and utilizing the existing site facilities mentioned above, in addition to the existing steam turbine generator, auxiliaries, and electrical interconnections, represent an installed cost savings of approximately $30 to $40 million as opposed to an entirely new, greenfield installation.

The estimated total installed capital cost for the Project is approximately $389 million, of which $255 million and $134 million are attributable to Destec and PSI respectively. These figures include escalation through 1995 (5% annually), environmental and permitting costs, startup costs, and license fees. On this basis, the total estimated developed and installed cost of the project is less than $1500 per kW of net generation.

The DOE Clean Coal Technology Program (Round IV) provided $219 million of cost-share funding for the project, $167 million for the design and construction phases, and $52 million for the three year demonstration phase. PSI and Destec are individually funding the balance of their respective portions of the job. The DOE funding reduces the estimated installed cost to less than $900 per kW of net generation.

Environmental Benefits

The plant is designed to substantially outperform the standards established in the Clean Air Act Amendments (the CAAA) for the year 2000. The Destec gasification technology will remove at least 98 percent of the sulfur in the coal. Expected SO_2 emissions will be less than 0.02 pounds per MMBtu of fuel. NO_x emissions from both the gasification block and the power block are expected to be less than 0.7 lb/MWh. CO_2 emissions will also be reduced approximately 20 percent on a per kilowatt-hour basis by virtue of the increased system efficiency. Figure 1 compares emissions of the pre-existing Wabash Unit #1 with expected emissions from the Project. By providing an efficient, reliable and environmentally superior alternative to utilities for achieving compliance with the CAAA requirements, the Wabash Project represents a significant demonstration of Clean Coal Technology.

A. EXPECTED PROJECT EMISSIONS

CGCC EMISSIONS	SO_2	NO_X	CO	PM	PM-10	VOC
Gasification Block Tons/Yr.	23	18	124	25	20	12
Power Block Tons/Yr.	204	774	374	46	42	13
Total CGCC Tons/Yr. (note 1)	227	792	498	71	62	25

B. COMPARISON TO EXISTING UNIT

EMISSIONS, LBS/MWH	SO_2	NO_X	CO	PM	PM-10	VOC
Unit 1 Boiler	38.2	9.3	0.64	0.85	0.85	0.03
CGCC	0.21	0.75	0.47	0.07	0.06	0.02
EMISSIONS, LBS/MMBtu						
Unit 1 Boiler	3.1	0.8	0.05	0.07	0.07	0.003
CGCC	0.02	0.08	0.05	0.01	0.01	0.003

(Based on 262 MW at 90% capacity factor)

Figure 1 - Environmental Emissions

REVIEW OF TECHNOLOGY

General Design and Process Flow

The Destec coal gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier which uses natural gas for startup. A process block flow diagram is shown in Figure 2.Coal is milled with water in a rodmill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600°F and 400 psig. Oxygen of 95% purity is supplied by a turnkey, 2060-ton/day low-pressure cryogenic distillation facility which Destec owns and operates.

In the first stage, coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas then flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value.

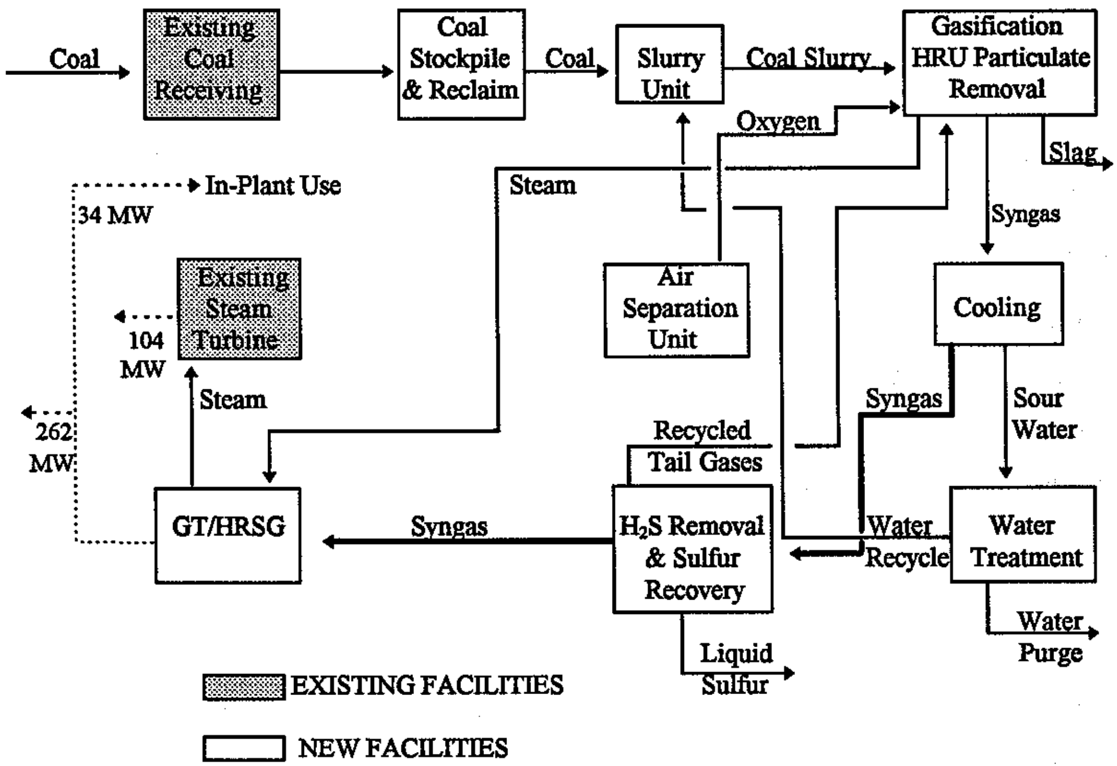

Figure 2 - Block Flow Diagram

The syngas then flows to the High Temperature Heat Recovery Unit (the HTHRU), essentially a firetube steam generator, to produce high pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted into syngas. Filter-element construction is a proprietary design proven at full scale at LGTI. The syngas is further cooled in a series of heat exchangers which additionally hydrolyze the carbonyl sulfide into hydrogen sulfide and remove the hydrogen sulfide using MDEA-based stripper columns. The "sweet" syngas is then moisturized, preheated, and piped over to the power block.

The key elements of the power block are the General Electric MS 7001 FA high-temperature combustion turbine/generator, the heat recovery steam generator (the HRSG), and the repowered steam turbine.

The GE 7FA is a dual-fuel machine (syngas for operations and No. 2 fuel oil for startup) capable of a surprising nominal 192MW due to the increased mass flows associated with firing syngas. Steam injection is used for NOx control, but the flow requirement is minimal compared to conventional systems because the syngas is moisturized at the gasification facility, making use of low-level heat in the process. The water consumed in this process is continuously made up at the power block by water treatment systems which clarify and treat river water.

The HRSG for this project is a single-drum design capable of superheating 754,000 lb/hr of high-pressure steam at 1010°F, and 600,820 lb/hr of reheat steam at 1010°F when operating on design-basis syngas. The HRSG configuration was specifically optimized to utilize both the gas-turbine exhaust energy and the heat energy made available in the gasification process. The nature of the gasification process in combination with the need for strict temperature and pressure control of the steam turbine led to a great deal of creative integration between the HRSG and the gasification facility.

The repowered unit, originally installed in 1952, consisted of a conventional coal-fired boiler feeding a Westinghouse reheat steam turbine rated at 105MW but derated in recent years to 90MW for environmental dispatch. Repowering involved refurbishing the steam turbine to both extend its life and withstand the increased steam flows and pressures associated with the combined cycle operation. Refurbishment of the steam turbine included

- modification & replacement of select blades in the low-pressure section to handle increased steam flow;
- many upgrades and modifications, notably: turbine controls, throttle valves, gland steam seals/controls, hydraulics, new condenser tubes, and removal of all extraction tubes except cold reheat;
- rewinding the generator rotor and stator;

The repowered steam turbine produces 104MW which combines with the combustion turbine generator's 192MW and the system's auxiliary load of approximately 34MW to yield 262MW (net) to the CINergy grid.

The ASU provides oxygen and nitrogen for use in the gasification process but is not an integral part of the plant thermal balance. The ASU uses services such as cooling water and steam from the gasification facilities and is operated from the gasification plant control room, but its air compression is not integrated with the combustion turbine compressor. Although some studies show that such integration can improve plant efficiencies, the Participants concluded that implementing new compression integration concepts would detract from the operability and availability of the Project in most operating scenarios.

The gasification facility produces two commercial byproducts during operation. Sulfur removed as 99.7 percent pure elemental sulfur via the gas clean-up systems will be marketed to sulfur users. Slag will be sold as aggregate in asphalt roads and as structural fill in various types of construction applications.

Thermal Integration

Although Destec and PSI independently designed, procured, and constructed their respective portions of the Project, cooperation during the design process allowed the Participants to maximize efficiency via thermal integration of systems and reduce costs by minimizing redundant systems. Condensate, feedwater, and steam flows are exchanged between the gasification island and the power block HRSG to maximize efficiency by making the best use of different levels of heat in each area.

Condensate from the steam turbine generator hotwell ("cold condensate" at about 88°F) is pumped 500 yards to the power block, conditioned for cycle chemistry requirements, and transferred to the gasification plant, where it is heated by hot syngas in need of cooling for the last stages of sulfur removal. Sulfur is removed from the syngas using conventional "cold" gas cleanup systems, some of which must operate at near-ambient temperatures. This stream, now at about 185°F and called "warm condensate", is combined with condensate produced by various intermediate pressure steam uses at the gasification plant and returned to the power block, where it is heated in the feedwater heater (the last heating section of the HRSG) and routed to the deaerator. The intermediate pressure steam requirements at the gasification plant are supplied from the steam turbine in the form of cold reheat steam.

Boiler feedwater from the deaerator is pumped through the HRSG economizer section. The water temperature is now elevated to approximately 560°F. A portion of this hot boiler feedwater flow continues through the HRSG in the conventional manner and becomes high pressure saturated steam (at about 1650 psia) in the HRSG evaporator section. The remaining hot boiler feedwater from the HRSG economizer is piped across the fence to the gasification plant, where it is split again. The main part of this flow acts as boiler feedwater for the gasification plant boiler, becoming high pressure saturated steam (1650 psia, 640°F). The remaining split of hot boiler feedwater is used for heating in the gasification process before being piped back to the economizer section of the HRSG as "boiler feedwater return" at about 410°F. High pressure saturated steam from the gasification plant is piped to the power block where it is combined with high pressure saturated steam from the HRSG. The combined flow passes through the HRSG superheater, exits at about 1010°F, and becomes the throttle steam for the repowered steam turbine. The cold reheat extraction flow from the steam turbine is heated in the HRSG and, after relinquishing splits for gas turbine NOx control steam injection and gasification plant intermediate pressure steam uses, is returned to the steam turbine where it is expanded and condensed.

Technical Advances

Using integrated coal gasification combined cycle technology to repower a 1950's-vintage coal-fired power generating unit essentially demonstrates a technical advance in and of itself.

More specifically, high energy efficiency and superior environmental performance while using high sulfur bituminous coal is the result of several improvements to Destec's gasification technology, including:

- Hot/Dry Particulate Removal, applied here at full commercial scale.
- Syngas Recycle, which provides fuel and process flexibility while maintaining high efficiency.
- A High Pressure Boiler, which cools the hot, raw gas by producing steam at a pressure of 1,600 psia.
- A Dedicated Oxygen Plant, which produces 95% pure oxygen for use by the Project. Use of 95% purity increases overall efficiency of the Project by lowering the power required for production of oxygen.
- Integration of the Gasification Facility with the Heat Recovery Steam Generator to optimize both efficiency and operating costs.

- The Carbonyl Sulfide Hydrolysis system, which allows such a high percentage of sulfur removal.
- The Slag Fines Recycle system, which recovers carbon remaining in the slag byproduct stream and recycles it back for enhanced carbon conversion. This also results in a higher quality byproduct slag.
- Fuel Gas Moisturization, which uses low-level heat to reduce steam injection required for NO_x control.
- Sour water treatment and Tail Gas Recycling, which allow more complete recycling of combustible elements, thereby increasing efficiency and reducing waste water and emissions.

The Project's superior energy efficiency is also attributable to the power generation facilities included in the Project. These facilities incorporate the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the steam turbine, including:

- The Project is the first application of Advanced Gas Turbine technology for syngas fuel, incorporating redesigned compressor and turbine stages, higher firing temperatures and higher pressure ratios, specially modified for syngas combustion.
- Repowering of the Existing Steam Turbine involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle is utilized.

PROJECT EXECUTION

Site Selection

Early site feasibility studies resulted in locating the new coal gasification repowering facilities northwest of PSI's existing Wabash River Generating Station (see Figure 3). The land for the Project was donated by the Peabody Coal Company. This property was formerly the Viking Mine, which once supplied the existing station with coal.

Locating the Project adjacent to the Wabash Generating Station minimized the cost of expensive alloy steam piping associated with connecting the repowered unit to the new CGCC facilities. Only Unit 1 (of 6) was repowered as part of the Project. Pre-existing facilities used by the Project include the rail and coal unloading facilities, the steam turbine & generator tandem, the condenser and auxiliaries, and the substation and related interconnects. The pulverized coal fired boiler associated with the #1 Unit was decommissioned. No new construction was required within the existing boiler and turbine buildings except for the steam piping and service water interconnections.

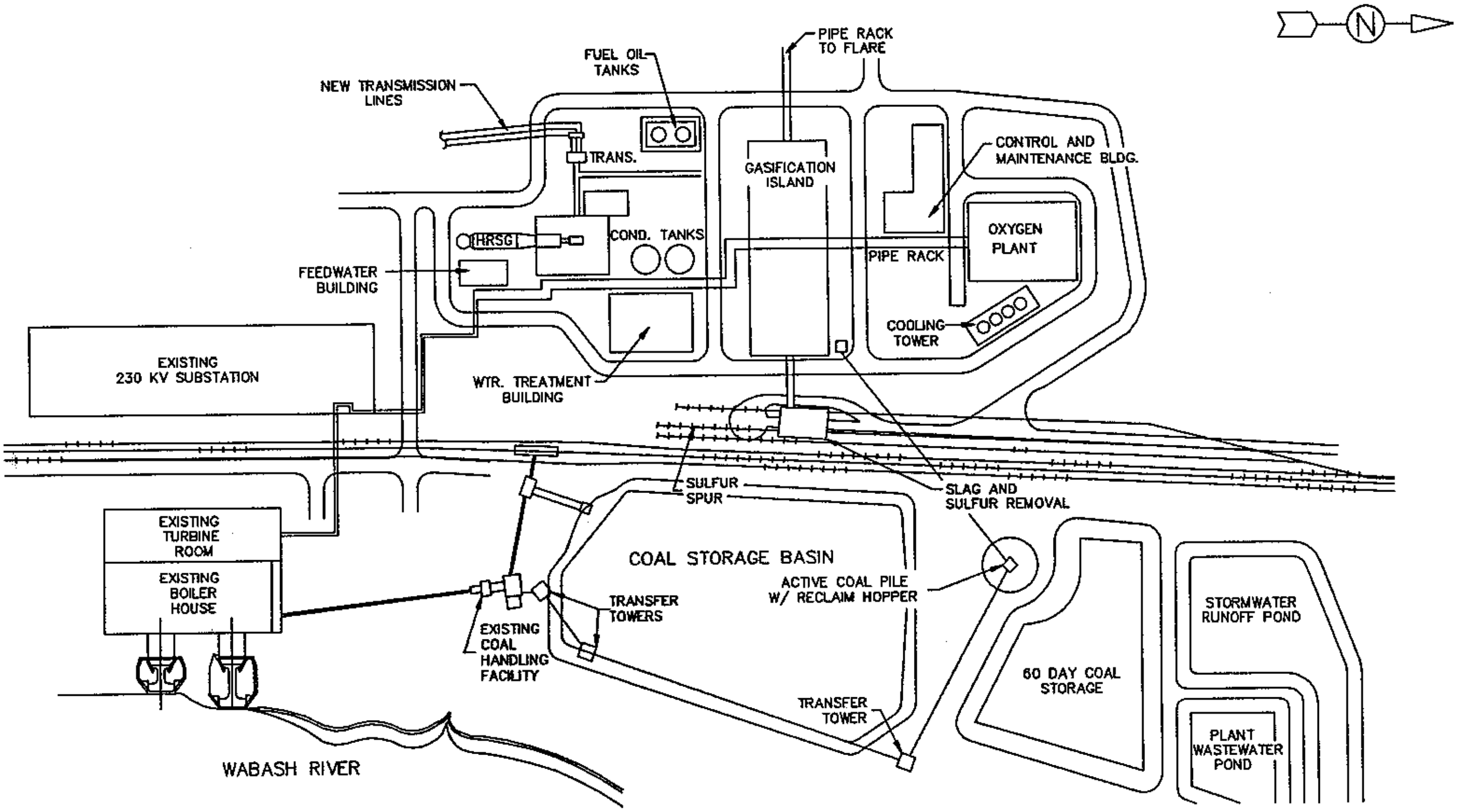

Figure 3 - Wabash River Coal Gasification Repowering Project Site

Although the integration of the coal gasification project with the existing station provides efficiency and cost advantages, the limitations on space presented challenges during construction, particularly the challenge of managing a construction manpower peak of over 1000 people for two separately-managed jobs on a small site. Additional site challenges included: 1) the need to reorient the physical layout of the gasification plant to protect against potential subsidence (based on site-specific data obtained during the engineering phase); 2) unstable mine spoils that made planned construction laydown and parking areas unsuitable for use; and 3) all of the site preparation work occurred in the spring of 1993, concurrent with rain that caused the 500 year flood in the midwest. Site mobilization was delayed three months.

Environmental Permitting

As a DOE sponsored project, the Project was subject to the requirements of the National Environmental Policy Act (NEPA). PSI, Destec and two environmental consulting firms were involved in the preparation of a detailed environmental information volume which was the basis for DOE's development of an Environmental Assessment of the impact of the Project. The favorable NEPA assessment resulted in DOE issuing a Finding of No Significant Impact (FONSI) in May 1993. Although the DOE supported the joint venture's efforts by expediting the review process, the FONSI was received approximately six months later than the original Project schedule. The Project was the first of its scope under the DOE Clean Coal Technology Program to obtain this status. The FONSI also demonstrates the advantage of repowering over greenfield construction.

The Project was also required to obtain other environmental permits. The most significant of these was the air permit. Because Destec had responsibility for the gasification plant and PSI had responsibility for the power generation portion of the Project, it was necessary for Destec and PSI to each obtain separate permits. However, for consistency and expediency, the Participants elected to perform air quality modeling studies on a combined basis. The total project was considered a modification to the PSI Wabash River Generating Station and environmental impact information was provided in combined form when possible. Communications between PSI, Destec, environmental consultants, and the permitting agencies (both state and federal) were managed through a multitude of face-to-face meetings. Both Destec and PSI received the requisite air permits in May 1993. The success of this "separate but together" approach, particularly with respect to the aggressive project schedule, has caused both corporations to re-think their traditional approaches to permitting and environmental issues.

In addition to the permit challenges posed by the joint venture structure itself, the Project faced the additional challenge of educating the permitting agencies about CGCC. Destec was specifically concerned about protection of proprietary technology and establishing a reasonable permitting precedent for future CGCC plants. PSI was concerned about obtaining credit for sulfur emission reductions. These goals were obtained, essentially establishing CGCC technology as a new emission credit methodology in the process.

Regulatory Approval

PSI needed a Certificate of Need from the Indiana Utility Regulatory Commission (IURC) in order to ratebase its portion of the Project. PSI and Destec both began submitting testimony to the IRUC in November 1991. The Project additionally required approval both as a Clean Coal technology addition *and* as a new capacity addition under state statutes. To qualify, the Participants demonstrated project economics outperforming alternative expansion scenarios by over $85 million. The Certificate of Need was issued to PSI in May 1993. Careful coordination between PSI and Destec, combined with clear communication between PSI and the Indiana Utility Regulatory Commission (IURC) allowed the Project to receive the Certificate despite opposition from competing capacity suppliers and an IURC that was unfamiliar with CGCC. The Gasification Services Agreement between PSI and Destec, with its careful allocation of risk and structuring of other commercial arrangements, was the key to developing a project that would obtain regulatory approval.

Financing

PSI Energy's portion of the project was a standard utility financing. Destec's goal was to obtain off-balance-sheet project financing for the gasification facility. This objective was a challenge since the banks had no previous experience with DOE Clean Coal Technology projects or coal gasification technologies. Ultimately, the banks were convinced that IURC approval, the GSA, Site Lease, and Cooperative Agreement, and the economic viability of the venture were adequate to assure repayment of their loan. The structure of the financing took the form of an operating lease where a subsidiary of Destec is the lessee and a bank is the trustee/owner. The term of the lease ends three years after startup of the project, after which Destec has the right to purchase the plant from the trustee. This structure keeps the plant off the books initially and enables Destec to form a conventional partnership after the plant has three years of operating experience and all elements of the plant are demonstrated.

Engineering, Procurement and Construction Management

Sargent & Lundy provided engineering services to PSI for the design and procurement of the modifications to the existing station, the new power block equipment, and the system integration interface to Destec. PSI managed the construction of the foregoing, which included the following new facilities:

- Combustion turbine
- Heat recovery steam generator
- Modifications to coal handling
- Oil storage tanks
- Piping additions
- Water treatment facilities
- Control room and buildings
- Stormwater and wastewater ponds

Dow Engineering Company, previous engineer for the LGTI facility, provided engineering services to Destec for the design and procurement of the gasification plant and the system integration interface to PSI. The Air Separation Unit was designed and built by Liquid Air Engineering Corporation. Destec managed construction of all facilities in the gasification island, including the Air Separation Unit and a control, administration and maintenance building.

Construction Challenges

Extensive pre-construction site work was required to level the Project site. Over 1 million cubic yards of dirt was moved in 1993 prior to mobilization of construction contractors in September. New construction took place in two areas. The 15 acre plot containing the gasification island, ASU, water treatment facility, and gas turbine-HRSG tandem is on a hill overlooking the existing station. The new wastewater and storm water ponds are located nearby in an area previously used as an ash pond.

Early in the construction schedule, activities were hampered by unusual weather conditions. The summer of 1993 was the wettest summer in Indiana history, with rains reaching the 500-year flood level. This was followed by the wettest November since 1888 and snow from Halloween through Easter. In addition, 1994 brought the coldest January on record for the state of Indiana, and ice storms shut down construction work in February. In order to stay on schedule, both PSI and Destec selectively employed 7-day construction schedules while trying to balance budget and schedule needs.

Peak construction activity brought over 1000 workers to the site daily, all working for a host of contractors and subcontractors, all ultimately reporting to either Destec or PSI. Project management expertise and coordination with, and support from, the local labor unions and contractors was critical to maintaining the Project schedule.

Other significant construction challenges were encountered, including:

- transport of large equipment to the site (some shipments had less than 2" clearance), despite flooded rivers, transportation strikes, and cross-country transport logistics;
- coordination of timing for interconnection responsibilities between the Destec and PSI portions of the Project; this challenge became critical as permitting and weather delays compressed the original construction schedule;
- the need to carry out a complex construction job with minimal impact to the existing PSI generating station;
- the need to make several heavy equipment lifts (up to 650,000 lbs) in a short period of time without disrupting other site activities.
- managing the disruption and schedule pressure associated with replacing key construction subcontractors.

The challenges of weather, schedule constraints, a small site, ongoing operations, component delivery and erection problems, the complexity of the job, labor shortages and subcontractor problems were all successfully met due to effective communication and coordination between the two Participants.

Project Schedule

Construction of foundations and steel erection commenced in September of 1993. Major equipment began arriving in early 1994 and all significant pieces were onsite by August. Steel erection and piping continued in parallel with equipment installation, which began in the fall of 1994. By late winter 1995, steelwork and major equipment installation was virtually complete, and construction efforts were focused on piping, controls, and instrumentation. By mid-June, virtually all of the combined facilities' 157 subsystems were turned over to operations personnel, whose commissioning activities were in full swing. Construction was complete in July of 1995 and commercial operations are expected to commence in August of 1995. Aggressive overlapping of engineering and construction activities, and assiduous communication and coordination between the two Participants enabled the Project to meet an ambitious two-year onsite construction schedule.

Coal Supply

The Wabash facility is designed to accept coal with a minimum sulfur content of 5.9% (dry basis) and an HHV of 13,500 Btu/lb (MAF). PSI has procured a coal which is consistent with the Performance Coal specification ranges of the GSA and the gasification facility. This coal, a high sulfur midwestern bituminous from the #6 seam at Peabody's Hawthorn Mine in Indiana, was selected with a view toward optimizing both the cost of coal and the overall performance of the CGCC system. It will be stored separately from the compliance coal to be burned in Units 2-6 of the existing station. Existing coal unloading facilities are shared with the new facility.

The Participants have the additional flexibility to substitute an alternative feedstock once per year for a maximum of 60 days during each of the three years of the Demonstration Period if they so choose. The alternative feedstock actually chosen for testing will be selected from among those representing either a viable opportunity for commercial application of the subject technology or an opportunity to evaluate the economic efficiency of alternative coals.

Staffing and Training

Destec's operator selection and training was simplified in that many operators from LGTI elected to relocated to the Wabash facility. In addition, twelve plant engineers and supervisors came from LGTI. From these experienced personnel, a ten-member core team was selected to work in concert with the Wabash design engineers and LGTI operations and technical staff to develop operating procedures and training programs for the Wabash plant. Operator selection and training was completed in September 1994, allowing about 12 months of training and comprehensive review board examinations prior to commercial operation. Total staffing for Destec's operation (gasification and ASU) is 66 people, with 36 O&M technicians.

PSI's operating personnel generally had prior experience in power plant operations and control systems. PSI's training structure incorporates process systems training, control board training, and specific equipment training. Due to limited experience with gas turbines, PSI developed a series of new operating and maintenance training programs in collaboration with key vendors, including a full-scale power block/thermal integration simulator developed with EPRI funding. Total staffing for PSI's O&M is 39, 27 of which are O&M technicians.

Turnover and Commissioning

A detailed turnover/commissioning plan was developed by a team of construction and operating personnel. After subdividing the CGCC system into logical, manageable process subsystems, the team developed a turnover/commissioning program for each subsystem and then sequenced all such programs into an overall schedule. Operating personnel also conducted system walk-throughs, witnessed hydrotests and alignments, participated in function-confirming activities and otherwise verified readiness of subsystems for operation, and developed punch lists. As before, the Participant's success in these activities was attributable to meticulous attention to coordination and communication.

OUTLOOK

Startup

Initial start up poses peculiarities not normally associated with utility operations. It will require that PSI and Destec closely monitor the interconnecting streams involved in the plant integration because it is driven by the sequencing of interrelated equipment and systems in the gasifier and combined-cycle facilities. Significantly, the oxygen plant must start first because the oxygen and nitrogen are used in the process which brings the gasification system up to operating temperatures. Once the syngas path reaches temperature, coal is introduced and the remainder of startup is relatively straightforward.

Operations

Although Destec and PSI will independently operate their respective gasification and power generation facilities, significant integration exists at the operating level. Operating interface parameters and other key data will be interchanged continuously between the gasification and power generation control rooms. In normal operation, syngas production will follow combustion turbine fuel demand. Thermal balance between the facilities is flexible to a certain extent, utilizing the heat recovery steam generator and gasification facility heat exchangers to follow syngas production. Once into commercial operations, startup and shutdown will continue to

require close coordination. The combustion turbine operates on auxiliary fuel (#2 distillate) at low loads during startup and shutdown. A "flying switch" will be made to syngas and the combustion turbine will ramp up to full load at its normal rates.
As mentioned earlier, the central objectives are to incorporate the system into the PSI system as a reliable and effective element of its baseload generation capability, and to demonstrate the operability, effectiveness, and economic viability of Destec's technology on a commercial scale and in a commercial utility environment. Destec plans to closely monitor the performance of key subsystems and components representing commercial applications of improved technology because the resulting availability and operating costs are expected to be favorably distinguishing. In addition, Destec plans to manage its operating discipline for continuous improvement, setting the stage and creating a standard for operation of the next Destec gasification facility.

PSI's major objectives involve making this facility a reliable and effective part of their baseload capacity, maintaining or improving the dispatch status of the facility, and managing costs. PSI will separately track and manage their cost-driven operating parameters, including the tracking of O&M costs broken down by labor, material, and fuel, capital expenditures, major overhaul expenditures, and preventable recurring costs as tracked by the maintenance management system.

Together, the Participants will monitor the operating characteristics which represent a baseload facility's ability to meet the requirements of its commercial environment, including start-up and shut-down times and costs (from cold and hot conditions), ramp rates on load changes, turndown ratios, stability of the plant at various loads, optimization of maintenance cycles for optimum availability, degraders, dynamic system response/control verification, and the like. Since dispatch status is a function of environmental and cost performance, the information representing such performance (operating, environmental, cost data) will be evaluated accordingly. Finally, since coal is the single largest energy cost component, PSI will continually pursue the lowest cost coal which meets the quality requirements of the GSA and the system.

STATUS UPDATE
POLK POWER STATION IGCC

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ABSTRACT

This paper will present a status update on Tampa Electric Company's DOE IGCC Project, Polk Power Station, Unit # 1. Engineering is currently complete and construction began in early 1994 with Site development activities. All major equipment has been received. The combustion turbine and generator, steam turbine generator, main air separation unit equipment, much of the sulfuric acid plant equipment, and the radiant syngas cooler have all been installed. Construction is about one-third complete. The electrical substation has been energized and start-up is just beginning. All of this activity is leading to project completion of late summer 1996.

INTRODUCTION

During the past five (5) years, Tampa Electric has been reporting on the theoretical plans, expected design, anticipated construction techniques, and artist concepts related to Polk Power Station Unit #1. We are finally at a stage in the Project where we have something concrete to report.

The detailed designs have now been completed, all equipment has been ordered, and most of it delivered to the Site. All erection contracts have been let, construction is almost 50% complete, and the initial phase of plant start-up has begun.

What we wanted to do for this conference is to provide a general overview of the Project and its technology and spend a little more time on the specific construction status and schedule for future activities.

As most of you are probably aware, this project was originally conceived to respond to the Program Opportunity Notice (PON) for DOE's Round III solicitation as part of the Clean Coal Technology program. The project was one of the 13 selected from 49 applicants. Notification of award was received from DOE in January 1990, by TECO Power Services (TPS) one of the original project partners.

The project is being installed at Tampa Electric's inland site in Polk County, Florida. This site is about 45 miles southeast of Tampa and 17 miles south of Lakeland, Florida, in the heart of the central Florida phosphate mining area. In fact, that mining is why the site was selected. The Polk site is on a tract of land that has been previously mined for phosphate, but not yet reclaimed. Installing the Polk IGCC on this site provided numerous, simultaneous benefits for TEC, Polk County, and reclamation advocates.

PROJECT APPROACH

We want to emphasize one important aspect of this Project which has been, and is becoming, a most significant and vital part of the success of this Project. We have tried to structure the entire Project on a win-win basis. This started with our involvement with DOE in 1990. Our cooperative agreement with DOE is based on a cost share arrangement in which DOE provides a significant portion of the capital and O&M expenses related to the Project. With this arrangement, DOE has a project that will significantly advance the state-of-the-art in integrated combined cycle plant development. DOE also gains tremendous insight into the design, construction and operation of IGCC and of hot gas clean-up (HGCU), a technology that is expected to advance future coal utilization and IGCC by improving heat rate, capital costs, and capacity. Along with the DOE benefits, TEC also gains from DOE involvement because, without this co-funding, Tampa Electric could not have selected IGCC for its capacity increase requirements.

In addition to DOE, the other major project participants are listed below:

Tampa Electric Company - Owner/Operator of Polk Power Station
TECO Power Services Corporation - Overall Project Management and Commercialization
Texaco Development Corporation - Licensor of Gasification Technology
General Electric - Supplier of Combustion Turbine/Combined Cycle Equipment
GE Environmental Services, Inc. - Designer of Hot Gas Cleanup System
Bechtel Power Corporation - Detailed Engineering/Construction Management Services
MAN Gutehoffnungshütte AG - Supplier of Radiant Syngas Cooling System
L&C Steinmüller GmbH - Supplier of Convective Syngas Cooling System
Air Products & Chemicals, Inc. - Turnkey Supplier for Air Separation Unit
Monsanto Enviro-Chem Systems, Inc. - Turnkey Supplier for Sulfuric Acid Plant
H.B. Zachry Company - Power Block Construction
The Industrial Company - Gasification Area Constructor
Johnson Brothers Corporation - Site Development and Reclamation
Aqua Chem - Supplier of Brine Concentration Plant
Davenport Mammoet Heavy Transport - Transportation/Erection of Radiant Syngas Cooler

Our contracts with our architect engineer (A/E) and construction manager (CM), Bechtel are intended to illicit an approach whereby they have a stake in the Project. These contracts are structured with very significant incentives where the more successful the Project is, the greater value of incentive payments they receive. This success is measured on those things that are most important to the owner, Tampa Electric (TEC), such as total Project cost, scheduled completion date, overall construction safety record, and plant performance, etc.

We have also structured our construction contracts in a manner which we feel will encourage the constructors to want this project to be a success and have tried to develop a true partnership approach with all these contractors.

With the major technology suppliers, (G.E., Texaco, Air Products, Monsanto, Bechtel), we have only selected contractors that are proven winners in the power or chemical industries and who are entirely capable and desirous of making Polk a complete success for <u>all</u> the involved Participants. We have chosen Johnson Brothers as the main Site development contractor, H.B. Zachry as the Power Block erector, and The Industrial Company (T.I.C.) as the gasification area contractor. All of the companies were chosen by competitive bidding, so we are ensured that in addition to top notch construction credentials, we have optimized the costs to the Project for these companies' services.

GOALS OF THE PROJECT

The overall project will integrate two major technologies - coal gasification and combined cycle power generation. This will allow us to use low cost coal with the efficiency of the combined cycle. This is expected to provide a system that is 10-12% more efficient than a conventional coal-fired unit. With the of exception the new HGCU technology, only commercially available equipment will be used for this project. The approach supported by DOE is the highly integrated configuration of these commercially available pieces of hardware or systems, in a new arrangement which is intended to optimize cycle performance, cost and marketability at a commercially acceptable size of nominally 250 MW (net).

The main objective of this plant is to provide electric power for the TEC's Customers. This unit is an integral part of Tampa Electric Company's generation expansion plan. That plan requires baseload capacity to be in service in the late summer of 1996. TEC's objective is to build a coal-based generating unit providing reliable, low cost electric power, using IGCC technology to meet those requirements.

From DOE's standpoint, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC unit using hot gas clean-up technology. In addition, demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO_2 and No_x emissions when compared to existing and future, conventional coal-fired power plants.

Via successful demonstration of this IGCC project, TEC will not only satisfy DOE's goal for providing a viable technology choice for future utility needs, it will also provide the opportunity for TPS to develop additional projects while "commercializing" the technology.

Our last formal estimate indicated a total project cost of $550,800,000., including capital, land, owners costs, and taxes. Current forecasts are up slightly from last year due, in part, to cost growth related to the Radiant Syngas Cooler, HGCU and project schedule impacts.

We expect to complete the project's construction and start-up by about September 15, 1996. This will then allow us to start the DOE Phase III of Demonstration Testing. This period will entail a two (2) year formal development of operating and maintenance data and performance parameters on four (4) different types of coal over this two (2) year period. Current plans call for testing of Pittsburgh #8, Illinois #6, Kentucky #9 and Elkhorn #3 coals. After the formal two (2) year demonstration period, TEC will continue to provide DOE with two (2) additional years of O&M data while operating on fuels determined by TEC to provide optimum operation benefit for its customers and shareholders.

PLANT DESCRIPTION

Combined Cycle

The main components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and generators.

The HRSG is installed in the combustion turbine exhaust to complete the traditional combined cycle arrangement and provide steam to a traditional steam turbine with a capacity of about 120 MW. No auxiliary firing is proposed within the HRSG. The HRSG will be used to recover the CT exhaust heat energy and for high pressure steam production from the coal gasification plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

The ST will be designed as a double flow reheat turbine with low pressure crossover extraction. The ST/generator will be designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1,400 psig and 990°F with 1,000°F reheat inlet temperature.

Gasification and Syngas Cooling

The gasification part of Polk has been developed based on Texaco's licensed technology. Also many of the design requirements for the syngas cooling system came from Texaco's experience at Cool Water, along with the operating and maintenance experience at the SAR plant in Oberhausen, Germany. Original bids had requested both single and dual RSC configurations. The DOE was interested in a large, single, commercial-sized RSC. Based on price considerations, and the DOE concerns, the single RSC configuration was chosen. The main-components are: Radiant Syngas Cooler (RSC), two identical Convective Syngas Coolers (CSC), a Raw Gas Clean Gas Exchanger (RGCGE), along with a mechanically identical Raw Gas Nitrogen Exchanger (RGNE). Also included were transfer lines between the RSC and CSC's, transfer lines between the CSC's and RGCGE and RGNE, high and medium pressure steam drums, circulating pumps and interconnecting piping.

Part of the reason for this configuration is to provide two parallel flows from the single RSC. The CSC's are designed so that their outlet temperature provides gas at the proper inlet temperature for the HGCU system. The purpose of the RSC is to cool the syngas and, in doing so, produce high pressure steam for use in the power block. The RSC is a water tube design. Systems were also required for removal of ash buildups and slag. Various alternatives for the tube materials were evaluated, with the prime concerns being gas side sulfidation corrosion during operation and water side corrosion during downtime. A fire tube design was required for the CSC.

The purpose of the RSC-CSC transfer lines is to provide a cooled surface in order to minimize building of stick ash. This is accomplished by using double pipe lines, and a substantial distance for flow to stabilize, with production of medium pressure steam at 450 psi.

The original specifications had called for all fabrication to comply with the appropriate ASME codes. During the evaluation period, bidders had provided cost decreases without compromising design criteria if equipment could be based on the European AD-Merkblätter Code.

From a design, engineering and fabrication standpoint, the RSC is on the critical path for the entire IGCC project. Due to the immense size and weight, transportation of the RSC from Belleli's facility in Italy to the Site was a major undertaking.

The RSC was shipped in two pieces : 1) the outer shell with the head on, and 2) the internal tube bundle. Davenport Mammoet Heavy Transport, Inc. was responsible for the entire job of transporting the RSC to the Site, and then erecting it into the gasification structure. The heavy lift work was subcontracted to Decalift.

The equipment was unloaded at Port Manatee on the west coast of Florida. From there, the equipment was moved by heavy transport vehicle on a 46 mile journey to the Site. Crossing Interstate 75, a major North-South artery down the west side of Florida, was a major obstacle, however via careful thorough planning, this was accomplished easily and required the Interstate to be closed for less than ten (10) minutes.

HGCU

HGCU was one of the primary criteria used by DOE for selecting the Polk IGCC project. The HGCU system is being developed by General Electric Environmental Services, Inc. (GEESI). The process is undergoing pilot plant testing at GE's laboratory facilities in Schenectady, NY. The advantage of the HGCU over CGCU is the ability to use the syngas from the gasification system, at 900-1000°F (480-540°C) instead of having to cool the gas to about 100°F prior to sulfur removal. The successful demonstration of this technology will provide for higher efficiency IGCC systems.

The gas supply for the HGCU system will come directly after one of the convective syngas coolers. The HGCU system will be sized to treat about 10% of the syngas. The unit will be able to operate on either the 100% CGCU or 90% CGCU/10% HGCU mode. One specific issue to be investigated in the HGCU system for our project is the metal oxide sorbent being demonstrated. Most of the HGCU testing to date has been done with zinc titanate as the sorbent material. This is a more robust material and more amenable to the oxygen-blown entrained-flow gasifier syngas than zinc ferrite, which is usually considered for air-blown gasifiers.

Two (2) other support processes will be investigated as improvements to this process. In addition to the high efficiency primary cyclone being provided upstream of the HGCU system, a high temperature barrier filter will be used downstream of the HGCU to protect the combustion turbine. Also, sodium bicarbonate, $NaHCO_3$, will be injected into the hot gas stream for removal of chloride and fluoride species. This will form the stable solids NaC1 and NaF, which will be collected in a secondary cyclone and disposed of with other plant solid by-product streams.

Integration

The key to success for the overall project will be the integration of the various pieces of hardware and systems. Maximum usage of the heat and process flow streams can usually increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other projects, such as Cool Water, to optimize the flows from different subsystems.

Probably, the most novel integration concept in this project is our intended use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is normally excess or wasted nitrogen, to increase power output and improve cycle efficiency and also lower No_x formation.

The heart of the integration concept is the distributed control system (DCS). Extreme effort was exerted to insure early receipt of vendor information so that all aspects of the integration could be considered at the onset of the project. We did two specific things which we hoped would maximize our chances of successful integration of all components and systems. First, we had and are continuing to do a thorough HAZOP analysis to consider all the things that could go wrong, from a design standpoint, before the system got to the field. The second thing was an intense and a complete factory checkout and simulation to insure both the design and fabrication were as close to perfect as possible, even before the DCS left the manufacturer's shop.

Balance of Plant

The CGCU system will be an enhanced amine type scrubber. Sulfur species removed in the HGCU and CGCU systems will be recovered in the form of sulfuric acid. This product has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of about 75,000 tons of sulfuric acid from this nominal 250 MW (net) IGCC unit will have minimal impact on the price and availability of sulfuric acid in the phosphate industry.

The Air Separation Unit (ASU) will use ambient air to produce oxygen for use in the gasification system and nitrogen which will be sent to the CT. The addition of nitrogen in the CT combustion chamber has dual benefits. First, since syngas has a substantially lower heating value than natural gas, a higher mass flow is needed to maintain total combustion turbine input. Second, the nitrogen acts to control potential No_x emissions by reducing the combustor flame temperature.

The ASU will be sized to produce about 2,000 tons per day of 95% pure oxygen and about 6,300 tons per day of nitrogen. The ASU is being designed and constructed as a turnkey project.

By Products

The Polk IGCC has been arranged to optimally generate by-products which can be sold in lieu of storing or stockpiling them on Site as a waste product. The slag from the gasifier will be sold to the same company that currently takes all the slag from Tampa Electric's other coal fired plants. They process that slag, which consists of inert, non-leachable, glass-like beads, into roofing shingles, blasting grit, and building materials such as concrete block and cement aggregate.

The sulfur removed from the gas steam downstream of the syngas coolers will be collected in the form of sulfuric acid and sold to the phosphate industry which uses sulfuric acid in quantities far greater than produced by Polk.

Our process water treatment system will convert what would otherwise be a wastewater stream into a brine product. This product will be taken to a nearby landfill operation or further processed into ammonium chloride for sale to local fertilizer companies.

Emissions

We expect the Polk emissions to be among the lowest in the United States for a coal-fired power plant. The primary source of emissions from the IGCC unit is combustion of syngas in the CT. The exhaust gas from the CT will be discharged to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily No_x and SO_2 with lesser quantities of CO, VOC, and particulate matter (PM). SO_2 emissions are limited by permit regulations to 0.247 lb/mm BTU during the initial two (2) year demonstration period but will be limited to 0.17 lb/mm BTU thereafter . Similarly, for No_x the limits are based on 0.3 and 0.1 lb/mm BTU (81 ppmvd and 25 ppmvd). The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some HGCU emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the initial 2-year demonstration period, the lower emission rates must be achieved for either CGCU or HGCU mode of operation to meet permit requirements. It is expected that at least 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems.

Schedule

The Polk project is currently right on schedule. The main power transformers were backfed the first of August this year, paving the way for the initiation of subsystem start-up and check-out. The cooling water pond system will be completed in October this year. This will conclude the 18 months required to reshape the "monscape". During this reclamation effort we moved over 12,000,000 cubic yards of material on the Site.

We expect to start check out of the ASU and sulfuric acid systems in December, 1995 and March, 1996 respectively. Coal will be fed to the gasifier in July, 1996, steam blows be completed in May, 1996. The CT will be fired on oil for check-out in April, 1996, and fired on syngas on July, 1996. The overall plant is scheduled to be ready for release to TEC's dispatch on September 15, 1996.

COMMERCIALIZATION

Current PC units have achieved their optimum efficiency limits and additional environmental restrictions do nothing more than add to PC units' unattractive financial position related to installation and O&M costs.

Integration of the gasification and combined cycle technologies is critical to developing, low capital cost, low O&M cost, low fuel cost, highly efficient and environmentally acceptable coal fired generating stations for the future use by electric utilities.

The gasification technology will provide the opportunity to use low cost fuels in an environmentally acceptable manner at a capital cost which is competitive with other available technologies. Gas fired combined cycle power blocks, adapted for use with low BTU syngas from the gasifier, provide increased efficiency benefits compared to PC units, even approaching the performance of natural gas fired installation.

CGCU systems have the capability to remove almost any potential pollutant subject to cost/benefit requirements. The HGCU system offers the potential to remove sulfur species from gas turbine fuels in a more cost effective manner due the reasons previously noted.

As we reported last year at this conference, we have found that this technology is vastly different from what we in the utility business are accustomed to using. The non-technical or business issues such as project management and contract administration also have significantly different requirements. The business issues must be successfully addressed by both the utilities and the different technology suppliers, in order for IGCC power plants to achieve ultimate commercial success. In our project, this has been a major task: meshing cultures from the utility, refinery, industrial, and sulfuric acid industries. Although it has been very different for us, we have successfully achieved a team concept that will be the template for IGCC units built in the future. We now have the team effort in place that will assure our Project's success, for <u>all</u> the participants. We still have room for improvement, but based on the changes made from last year, we have no doubt that we will all succeed in our collective goal to demonstrate IGCC commercialization.

The entire gasification industry needs to continue to develop methods for processing coal into fuel gas in a manner that minimizes emissions of environmentally sensitive constituents. There still will be required an intensified effort by technology vendors in the general gasification area and integration concepts to develop and implement improvements, in order to support long term commercial viability of IGCC.

From TPS's standpoint, we see few current applications for immediate domestic application of IGCC. There are numerous opportunities in the Asia or the Pacific Rim, but these are not being pursued by TPS as a strategic market due to TPS's size and the tremendous competition in this area. Markets are just beginning to open up in Europe, but TPS has not yet focused in that sector. Numerous applications exist in Central and South Americas. These areas are experiencing astronomical growth and the current political and financial situations there are improving.

In order for IGCC to become fully accepted and politically and financially successful several hurdles need to be cleared.

1. Natural Gas Prices continue to be too low for IGCC capital requirements to compete with and overcome their current disadvantage. We would expect this trend to exist for the next few years then start shifting towards IGCC economics becoming more favorable.

2. The heart of the IGCC technology is high efficiency related to higher firing temperatures of the advanced CT's. The manufacturers of these CT's are just now seeing some operational and design challenges develop. TPS would expect that within the next 2-3 years all these issues will be resolved as they were with previous generations of CT's.

3. If HGCU to be competitive, sorbent development will have to improve rapidly. Currently this development is about 2-3 years behind the IGCC technology development. If and when this sorbent technology catches up with IGCC technology, the HGCU can become competitive with other clean coal technologies.

4. Current costs for first generation IGCC hardware and technology are deterrents to commercialization of IGCC. As more and more IGCC's are brought on-line, then costs will fall in line. This should occur within the next few years also.

These hurdles reflect exactly to the situation that currently exists at the Polk IGCC. Government co-funding is currently required to make IGCC cost competitive. However, successful completion of Polk Power Station - Unit #1 should go a long way to clearing these hurdles and making IGCC the cost competitive and desirable technology that the utility industry is looking to see.

GLOSSARY

ASME	American Society of Mechanical Engineers
ASU	Air Separation Unit (Oxygen Plant)
BTU	British Thermal Unit
CGCU	Cold Gas Clean Up
CO	Carbon Monoxide
CSC	Convective Syngas Cooler
CT	Combustion Turbine (Gas Turbine)
DCS	Distributed Control System
DOE	United States Department of Energy
GE	General Electric
GEESI	General Electric Environmental Systems, Inc.
HAZOP	Hazard and Operability Analysis
HGCU	Hot Gas Clean Up
IGCC	Integrated Gasification/Combined Cycle
O&M	Operation and Maintenance
PC	Pulverized Coal
PM	Particulate Matter
RGCGE	Raw Gas/Clean Gas Exchanger
RGNE	Raw Gas/Nitrogen Exchanger
RSC	Radiant Syngas Cooler
ST	Steam Turbine
TEC	Tampa Electric Company
TPS	TECO Power Services

THE PIÑON PINE IGCC PROJECT: ADVANCED COAL-FIRED POWER GENERATION SYSTEMS

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ABSTRACT

Currently, virtually all new electric power generation systems being constructed are being designed with natural gas as the primary fuel. Factors driving these construction decisions involve sustained low prices for natural gas, environmental (and consequent regulatory) risks associated with use of coal for power generation, and relatively high costs of construction for conventional coal-fired powerplants. Despite the unarguable abundance of coal in the U.S. and worldwide, a fundamental question arises: What will be the role of coal in electric power generation in the 21st century?

Congress, recognizing the vital and strategic importance of preserving the coal option for electric power generation, authorized the Clean Coal Technology Program. This program, with original funding in excess of $2,500 million, is intended to promote the demonstration and commercialization of a new generation of clean, efficient coal-based energy technologies through collaboration and partnering with private industry. Recent Congressional budget-cutting efforts, however, could threaten the effectiveness of that model program, and ultimately other subsequent government-industry collaboration.

Sierra Pacific Power Company is building an Integrated Coal Gasification Combined Cycle (IGCC) power plant. The project was selected by the U.S. Department of Energy (DOE) for funding under the fourth round of the Clean Coal Technology Program and is being constructed at Sierra's existing Tracy power plant site located 20 miles east of Reno, Nevada. The project has been designated the Piñon Pine Power Project; a DOE-SPPCo. Cooperative Agreement for the project was completed in July, 1992 and will provide for approximately $154 million of funding.

The project will utilize the Kellogg-Rust-Westinghouse (KRW) fluidized bed ash agglomerating gasifier in an air blown mode; hot gas cleanup will be accomplished by employing ceramic candle filters and a mixed metal oxide sorbent for sulfur absorption. Compared with conventional oxygen-blown gasification systems using cold gas cleanup, the advanced air-blown design offers significant potential for reducing complexity and consequently capital and operating costs. Construction began in early 1995, and will be complete in late 1996.

This paper will provide an update on the technology, the project status, and offer thoughts concerning the future of coal-based power generation.

INTRODUCTION

Public Law 101-121 provided $600 million to conduct a fourth round of federally cost-shared Clean Coal Technology (CCT) projects to demonstrate technologies capable of replacing, retrofitting or repowering existing facilities. Following three previous solicitations in 1986, 1988, and 1989, the U.S. Department of Energy (DOE) issued a Program Opportunity Notice (PON) for CCT-IV in January 1991, soliciting proposals to demonstrate innovative, clean, and energy efficient technologies capable of being commercialized in the 1990's. These technologies were to be capable of (1) achieving significant reduction in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities, and/or (2) providing for future energy needs in an environmentally acceptable manner.

Sierra Pacific Power Company's (SPPCo.) CCT-IV proposal to DOE was for the design, engineering, construction, and operation of a nominal 800 ton-per-day (86 MW_e gross), air-blown Integrated Gasification Combined Cycle (IGCC) project to be constructed at SPPCo's existing Tracy Station, a 400 MW, gas/oil-fired power generation facility located on a rural 700+ acre plot about 20 miles east of Reno (see **Figure 1**). SPPC will own and operate the demonstration plant, which will provide power to the electric grid to meet its customers' needs.

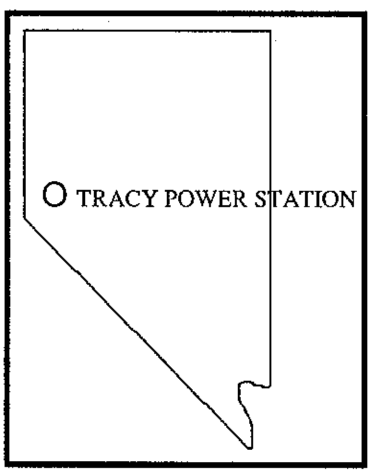

Figure 1. Location of Piñon Pine Power Project within State of Nevada.

The Federally cost-shared portions of the Piñon Pine Power Project are scheduled to take 96 months, including construction, startup, and a 42-month demonstration phase, at a total project cost of $308 million. SPPC and DOE will share equally in project costs. Of SPPC's $154 million share[1], capital costs of approximately $220 million are projected, with the balance funding fuel and operations & maintenance expenses. After the DOE demonstration period, Sierra will continue to utilize the plant for electric power generation to meet its customers needs; expected plant life will be in excess of 20 years.

SPPC has contracted with Foster Wheeler USA Corporation (FWUSA) for engineering, procurement and construction management services for the project. FWUSA in turn will subcontract with The M.W. Kellogg Company (MWK) for engineering and other services related to the gasifier island.

The project is currently in construction. Permitting for construction is complete, and environmental monitoring activities are continuing. This paper provides an overview of the project, the technology, and an update on project status.

PROJECT OBJECTIVES AND SCHEDULE

SPPC's primary objective for the Piñon Pine Power Project is to utilize advanced technologies to produce a clean and low-cost power supply to meet our increasing customer needs. Additional goals of the project are to demonstrate air-blown, pressurized fluidized-bed IGCC technology incorporating hot gas cleanup; to evaluate a low-Btu[2] combustion turbine fuel gas; and to assess long-term reliability, maintainability, and environmental performance at a scale sufficient to demonstrate further commercial potential. The plant will also provide economic benefits to the state and local community through employment and increase in the tax base. The project is expected to employ a construction workforce of 500 during peak construction years of 1995-1996. Once complete, the plant is expected to provide about 30 new, permanent jobs.

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[1] All figures are in "as-spent" dollars, which include projected inflation

[2] Heating value of the gas will be between 93-130 Btu/scf (LHV), depending on the final choice of desulfurization sorbent selected.

Federal cofunding of the project automatically invokes environmental review under the National Environmental Policy Act (NEPA). This project thus required an Environmental Impact Statement (EIS) with DOE as the lead agency. All work in support of the DOE's preparation of the EIS was completed, and the Final Environmental Impact Statement was issued in September, 1994. A favorable Record of Decision was issued November 8, 1994. All other permits needed for construction were received by January, 1995. Construction commenced in February, 1995.

The project required approval by the Nevada Public Service Commission (PSCN) pursuant to the State's Resource Planning process. In 1992, Piñon was included in SPPCo's Electric Resource Plan to the PSCN, with the project identified as part of the Recommended Resource Plan. In November 1992, the PSCN issued an order directing SPPCo to continue work on the project, and affirmed the prudence of continuing such work. SPPCo was further ordered to refile the "supply-side" portion of its plan, specifically addressing load uncertainty issues associated with a recently proposed natural gas pipeline in northern Nevada. Final PSCN approval for the project was rendered in late 1994, and in January 1995 the PSCN issued the Permit to Construct.

SPPCo is in the process of merging with the Washington Water Power Company, headquartered in Spokane, Washington. This "merger of equals" is a strategic positioning of the two companies, and will not affect the project.

As shown in the project schedule (**Figure 2**), SPPCo expects to have the plant commissioned by late 1996 to meet load requirements, as well as to utilize Internal Revenue Code (Section 29) tax credits. The demonstration period will run from February 1997 until August 2000.

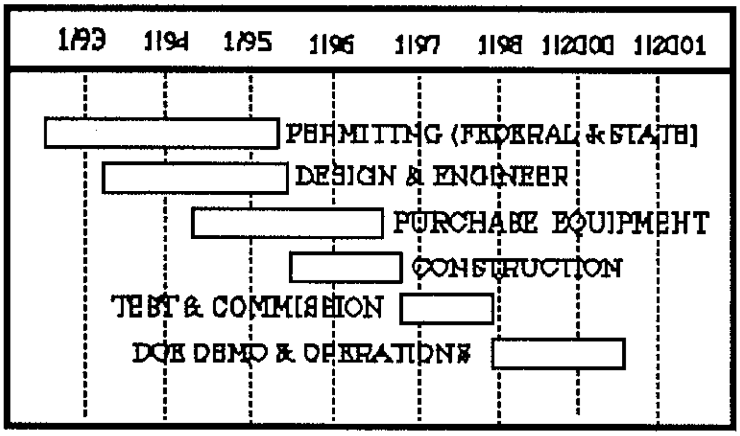

Figure 2. Project Schedule.

TECHNOLOGY

A preview of a future in which advanced technology will generate environmentally clean, affordable electricity from coal will be seen at the Piñon demonstration plant.

The Piñon Pine IGCC is expected to improve upon first generation IGCC technology in several aspects. The Piñon Pine Project integrates a number of technologies fostered by the DOE. Among these are the KRW Energy Systems fluidized bed ash-agglomerating gasifier, in-bed desulfurization using limestone sorbent, and a proprietary zinc oxide based (Phillips Z-Sorb®) sulfur removal sorbent from a hot gas stream using an advanced transport reactor design. Tiny ash particles will be removed from the gases leaving the gasifier by a combination of cyclones and ceramic filters. The cleaned gas will be burned in a combustion turbine to generate one souce of electricity. Exhaust gas from the turbine will be used to produce steam to drive a steam turbine generator to produce a second source of electricity. Together, the two generators will produce approximately 107 megawatts (gross) of electricity.

The demonstration of the advanced IGCC technology will include integration of the gasifier with a combined cycle power plant. This step is necessary in order to prove the adequacy of integrated control concepts and measure actual performance of a complete power generation system on a utility grid. The modular concept of the proposed technology will provide information directly applicable to other commercial plants, since such plants will essentially incorporate one or more replicates of the demonstration project plant configuration.

Details of the technology have recently been published in numerous papers and reports [see References Section] and will not be repeated herein. Technically inclined readers are particularly directed to the recent Public Design Report [23], and the 1994 Annual Report [25] for more information. Both publications are available from the Morgantown Energy Technology Center (METC).

PROJECT STATUS

Construction began in February, 1995. To date, site grading is essentially complete, foundation work is well underway, and structural steel erection will begin in September. The scope of the project is indicated by the quantities of "bulk" materials used, as indicated in **Table 1**.

Concrete	14,000 cubic yards	
Structural Steel	4.2 million pounds	
Pipe	24,500 lineal feet	large bore (>3")
	51,300 "	small bore (under 3")
	27,700 "	underground
Cable	34,000 lineal feet	underground
	365,000 "	power distribution
	133,000 "	lighting
	12,000 "	intercom/PA
	238,000 "	instrument/control

Table 1. Quantities of Bulk Materials - Piñon Project

Procurement of equipment has proceeded to the point that approximately 95 percent of equipment has been selected, and released for fabrication. **Table 2** is a list of some of the key equipment and the selected vendors of that equipment.

• Gas Turbine Generator	General Electric
• Steam Turbine Generator	General Electric
• Low Pressure and High Pressure Boiler Feedwater Pumps	BW / IP
• Heat Recovery Steam Generator	Applied Thermal Systems
Stacker Reclaimer	Krupp-Robins
• Step-up Transformers	Pauwels, Canada
• Surface Condenser	Graham Manufacturing
• Steel for Combined Cycle & Offsites	Gremp
• Steel for Gasifier Structure	Central Texas Iron Works
• MWK Heat Recovery Steam Generator	ABCO
• Recycle Gas Cooler	Ohmstede
• Product Gas Cooler	Schmidt'sche, Germany
• Product Gas Trim Cooler	EFCO
• Primary Solids Cooler	Yuba Heat
• Sulfator	General Welding
• Transport Desulfurizer	American Engineers, (J. T. Thorpe)
• Transport Regenerator	American Engineers, (J. T. Thorpe)
• Gasifier	Mark Steel
• Gasifier Refractory	J. T. Thorpe
• Gasifier Steam Drum	Struthers Industries
• Gasifier Primary Cyclone	Van Tongeren
• Desulfurizer Cyclone	Emtrol
• Regenerator Cyclone	Emtrol
• Booster Air Compressor	Atlas Copco
• Hot Gas Filter	Westinghouse (Enpro)
• Refractory Lined Piping	American Engineers
• Refractory Lined Valves	Enpro
• Coal Feeders	Macawber
• Gasifier Ash Feeder	Young Industries
• Filter Fines Screw Cooler	Christian
• Sulfator Solids Screw Cooler	Christian

Table 2. Major Equipment Suppliers - Piñon Project.

COMMERCIALIZATION

The advanced KRW gasification technology with hot gas clean up offers significant advantages over other gasification schemes. Consequently, SPPCo, Foster Wheeler USA and The M.W. Kellogg Company are optimistic regarding the commercial potential of this approach.

The M.W. Kellogg Company and Foster Wheeler USA have entered into a Licensing Agreement to commercialize the KRW gasification technology that is being demonstrated at the Piñon Pine project. The agreement is exclusive in the U.S. and can be extended to projects outside of the U.S. Under the Agreement, Foster Wheeler will market the KRW technology through their boiler equipment sales offices that are in continuous contact with utility customers. Kellogg will retain the responsibility for the maintenance of and improvements to the technology. SPPCo has agreed to support the commercialization of the technology through sharing of their operating experience with potential clients and future users of the technology.

SPPCo, Foster Wheeler and The M.W. Kellogg Company believe that the Integrated Gasification Combined Cycle (IGCC) technology being demonstrated at the Piñon project will be successful and will enjoy a significant share of the power generation market in the 21st century.

REFLECTIONS ON THE FUTURE OF ADVANCED COAL-BASED POWER SYSTEMS

Currently, virtually all new electric power generation systems being constructed are being designed with natural gas as the primary fuel. Factors driving these construction decisions involve sustained low prices for natural gas, environmental (and consequent regulatory) risks associated with use of coal for power generation, and relatively high costs of construction for conventional coal-fired powerplants. Despite the unarguable abundance of coal in the U.S. and worldwide, a fundamental question arises: What will be the role of coal in electric power generation in the 21st century?

Congress, recognizing the vital and strategic importance for preserving the coal option for electric power generation authorized the Clean Coal Technology Program. This program, with original funding by Congress in excess of $2,500 million, is intended to promote the demonstration and commercialization of a new generation of clean, efficient coal-based energy technologies through collaboration and partnering with private industry. Recent Congressional budget-cutting efforts, however, could threaten the effectiveness of that model program, and ultimately other subsequent government-industry collaboration.

The author will share his views on the future of advanced, coal-based power system and the directions being taken by the Clean Coal Technology Program.

LIST OF ABBREVIATIONS/ACRONYMS

CCT	Clean Coal Technology
DOE	U.S. Department of Energy
EIS	Environmental Impact Statement
IGCC	Integrated Gasfication Combined Cycle
KRW	Kellogg-Rust-Westinghouse
MW	Megawatt, a unit of electrical power equal to 1000 kilowatts
NEPA	National Environmental Policy Act
PON	Program Opportunity Notice (solicitation for CCT Program)
PSCN	Public Service Commission of Nevada
SPPCo.	Sierra Pacific Power Company

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Fourth Annual Clean Coal Technology Conference
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Coal-Diesel Combined-Cycle Demonstration Update

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ABSTRACT

Cooper-Bessemer and Arthur D. Little have developed a new technology to enable coal-water slurry (CWS) to be utilized in large-bore, medium-speed diesel engines. The technology includes emissions controls which position the coal-fueled diesel as a new option for IPP's and small utilities as they plan new capacity to meet Phase 2 Clean Air Act Amendment requirements. Modular power generating applications in the 10-100 MW size are the target applications for the late 1990's and beyond, when, according to the U.S. DOE and other projections, oil and natural gas prices are expected to escalate much more rapidly compared to the price of coal. Interest in coal-fueled heat engines revived after the fuel price hike in the 1970's. Based on the success of exploratory engine tests with micronized coal-water slurry in the early 1980's, Morgantown Energy Technology Center (METC) of the U.S. Department of Energy initiated several programs for the development of advanced coal-fueled diesel and gas turbine engines for use in cogeneration, small utilities, industrial applications and transportation. The Cooper-Bessemer/Arthur D. Little program was sponsored by METC and has now advanced to the field demonstration stage under DOE Clean Coal Technology (CCT-V).

As part of the earlier Cooper-Bessemer/Arthur D. Little program, over 1050 hours of prototype engine operation has been achieved on engine-grade, 1.7% ash coal-water slurry, including over 200 hours operation of a six cylinder, full-scale, 1.8 MW LSC engine with an Integrated Emissions Control System in 1993. In this paper, the authors update the progress of the coal-diesel engine combined-cycle (CDCC) demonstration under the CCT project. We also describe the process for preparing the CWS fuel, the heat rate of the engine operating on CWS, the performance of the CWS fuel storage and delivery subsystem, and the demonstrated low emissions characteristics of the coal-fueled diesel system.

CLEAN-COAL-DIESEL TECHNOLOGY DESCRIPTION

The coal-diesel, combined-cycle (CDCC) plant is an innovative, modular, clean-coal technology developed under the auspices of the U.S. Department of Energy. The 10-100 MW capacity range for this technology is targeted at the non-utility generation market. As such, the Clean-Coal Diesel fills a critical gap in the portfolio of existing Clean Coal Technologies; below 100 MW there is no other competitive coal-to-busbar power plant technology.

The estimated performance characteristics of the mature commercial embodiment of the Clean-Coal Diesel, if achieved, will make this technology quite competitive:

- 48% efficiency (6830 Btu/kWh heat rate)
- $1300/kW installed cost
- Emission level controlled to 50-70% below current New Source Performance Standards

The CDCC plant incorporates Cooper-Bessemer CSVC-20 engines integrated with a Rankine bottoming cycle. A schematic of a typical plant is shown in Figure 1. The advanced technologies developed to power these engines with coal include: cost effective coal preparation to provide an "engine-grade" coal-water slurry; durable engine components; and an emission control system.

PROJECT GOALS AND PARTICIPANTS

One of the five projects selected for DOE funding in CCT round five is a project proposed by a team led by Cooper-Bessemer Reciprocating Products Division of Cooper Cameron, Inc. (Cooper), and Arthur D. Little, Inc. (ADL) with additional support from the Ohio Coal Development Office (OCDO). The proposers requested financial assistance from DOE for the design, construction, and operation of a nominal 90 ton-per-day, 14-megawatt electrical (MWe), diesel-engine-based, combined-cycle demonstration plant using coal-water slurry. The project is named the Coal Diesel Combined Cycle Project and will use Cooper-Bessemer diesel engine technology. The demonstration plant will produce electrical power to serve the host site's power grid. The project, including the demonstration phase, will last 79 months at

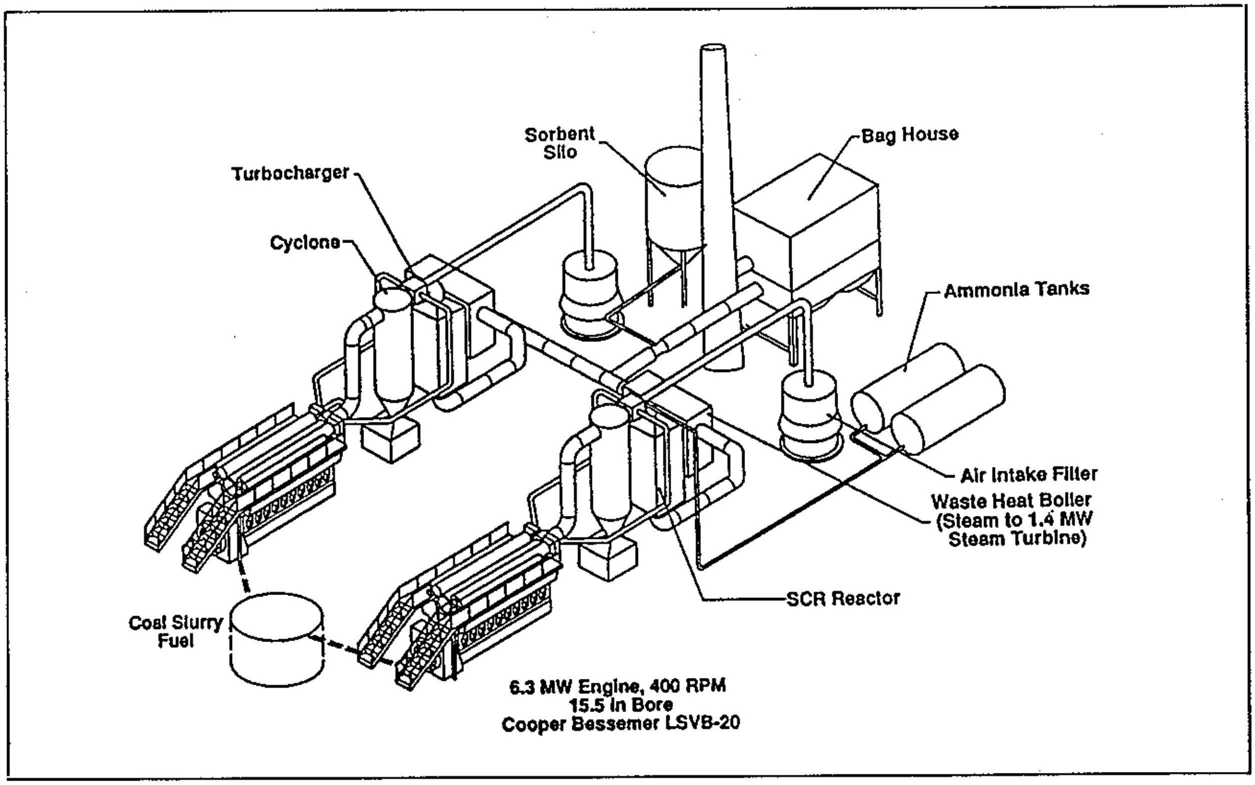


Figure 1: CDCC Plant Isometric

a total cost of $38,309,516. The schedule for Phase I is shown in Figure 1A. DOE's share of the project cost will be 50 percent. ADL is the prime contractor (participant) for the project.

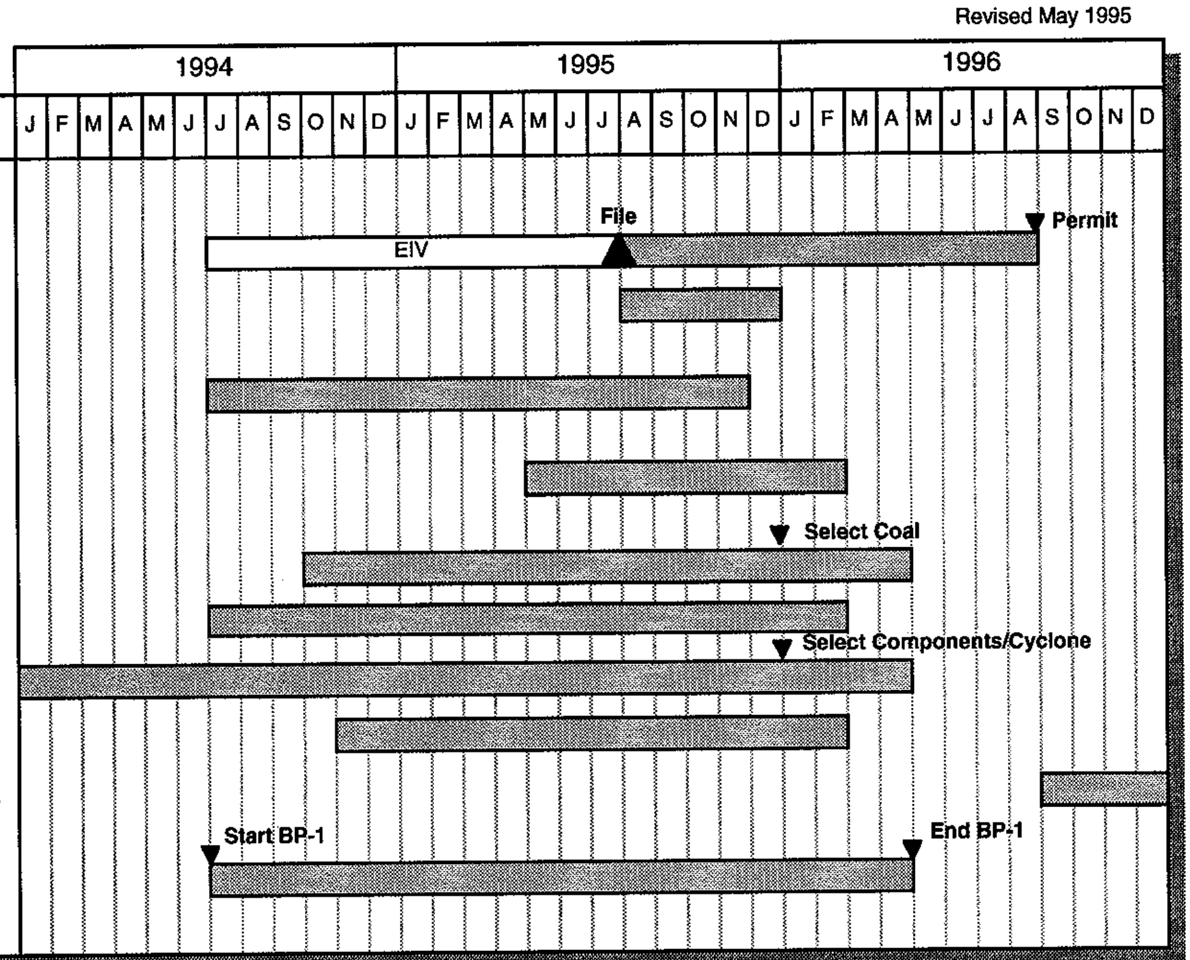
The objective of the project is to demonstrate an advanced, coal-diesel engine combined-cycle system in a small utility power plant. The integrated system performance to be demonstrated will involve all of the subsystems, including coal cleaning and slurrying systems; a selective catalytic reduction (SCR) unit, a dry flue gas scrubber, and a baghouse; two modified diesel engines; a heat recovery steam generation system; a steam cycle; and the required balance of plant systems.

If the project is as successful as anticipated, it will demonstrate that integrated, coal-fueled, combined-cycle power plants based on the CDCC technology can be built at capital costs and thermal efficiencies which significantly reduce electric power costs over more conventional technologies for the 10 to 100 MWe range. The project will also demonstrate the

Figure 1A — Coal Diesel Combined-Cycle Project

CCT - V Project Schedule

TASK	Description	Start	Finish
PHASE I - Design		*1st of*	*30th of*
1.1	Permit/Certificates/EIV	Jul 94	Aug 96
1.2	Easton plant preliminary design	Aug 95	Dec 95
1.3	Environmental monitoring plan/test plan	Jul 94	Nov 95
1.4	Design 20-cyl. engine components	May 95	Feb 96
1.5	Coal slurry qualification tests	Oct 94	Apr 96
1.6	Emission system design	Jul 94	Feb 96
1.7	6-cyl. lab. engine tests	Jan 94	Apr 96
1.8	Ccal cleaning plant design	Nov 94	Feb 96
1.9	Easton plant design engineering (following permit)	May 96	Aug 96
1.1	DOE reports and project reviews - Phase I	Jul 94	Apr 96



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effectiveness of SCR and other exhaust-gas-cleanup systems in achieving a negligible environmental impact with bituminous coal.

CLEAN-COAL-DIESEL TECHNOLOGY DESIGN AND PERFORMANCE

Key Phase I Accomplishments

- We have identified three coal seams underlying seven Ohio counties that contain reserves cleanable to the ash level required for engine grade fuel.
- Miller Mining's Ragersville coal, which has been cleaned to 2.0% ash, has been selected for Phase I engine tests at Cooper.
- Cooper's single-cylinder JS-1 engine has been prepared for tests that will qualify Ohio coal.
- We have developed new coating specifications for engine exhaust valves to reduce wear.
- We have conducted cyclone physical modeling tests that reveal the cause of prior performance problems and have developed design modifications to improve particle removal efficiency.

Coal-Water Slurry Specification, Preparation, and Handling

CWS Specification for Engine Testing

Based on extensive testing, the specifications for lower cost coal slurry for the LSC 6-cylinder engine tests were established as follows: 2% ash or less, 88 micron top size, 12-15 micron mean size, 51% max solids, and <200 cp viscosity. Over 44,000 gallons of slurry were produced at CQ Inc. for engine testing. Clean coal for this slurry was produced using conventional, heavy media cyclones in the circuit described below. The grinding circuit and additive package used by CQ Inc. to produce the fuel was developed in partnership with Energy International. Additional coal-water slurry prepared by Otisca was used for LS-1 engine tests and was stored as a "back-up" fuel for LS-6 engine tests.

Coal Cleaning and Preparation Circuit

CQ Inc. procured coal from the Wentz Mine of Westmoreland Coal Company located in Wise County, Virginia. This Taggart Seam coal was cleaned at the commercial cleaning plant at the mine to approximately 3.0 percent ash content (on a dry basis). The quality (dry basis) of a typical shipment of this coal received at the CQDC was:

Ash (Wt %)	2.69
Sulfur (Wt %)	0.63 (equiv to 0.83 lb/MMBtu of SO_2)
Heating Value (Btu/lb)	15,149

Characteristics of Pre-cleaned Coal Feedstock

Coal shipped from the mine had a nominal top size of two inches. The coal was cleaned using a heavy-media cyclone circuit. Feed coal was metered from the storage bins using weight feeders and conveyed at 15 tons/hr to the coal cleaning plant, which was configured to clean the coal using the heavy-media cyclone circuit. The specific gravity of the media was controlled to effect a separation at the appropriate specific gravity (1.28-1.30) to provide the low ash product. The coal was cleaned to 1.5 percent ash (dry basis) with a yield of approximately 65%.

The quality of a typical batch of clean Taggart Seam coal produced by this circuit was as follows (on a dry basis):

Ash (Wt %)	1.50
Sulfur (Wt %)	0.59 (equiv to 0.78lb/MMBtu of SO_2)
Heating Value (Btu/lb)	15,074

Characteristics of Engine-grade Coal

The re-cleaned coal was loaded into storage bins to be fed to the coal-water slurry preparation circuit.

CQ Inc. devised a continuous grinding circuit to produce coal-water slurry with similar properties to the fuel developed by Energy International for the coal-diesel application. The specifications for the coal-water slurry were:

- Mass mean diameter of less than 15 μm, maximum less than 88 μm (measured by Microtrac™ particle size analyzer).
- 50.0 to 53.0% (51.5% target) solids loading.
- Viscosity of <200 centipoise @ 100-1000 $sec.^{-1}$ (measured by a Haake rotoviscometer).

Clean coal was metered from the 15-ton bin at a rate of about 1.1 tons/hr. The coal (3/8" top size) was crushed to 16 mesh (0.04"). The crushed coal was then mixed with half the total dispersant loading and enough water to obtain about one percentage point over the desired solids content. The coal-water-dispersant mixture was fed to a MPSI 4 ft x 7 ft tumbling ball mill. The ball mill product discharged via a trommel screen to prevent loss of the grinding media. A quarter of the total dispersant was added to the ball mill discharge.

The ball-milled coal was pumped to a 200-liter Netzsch horizontal-agitator bead-mill where its size was further reduced. Stabilizer (xantham gum) and the last quarter of the dispersant was added to the bead-milled discharge coal and pumped to a 48-inch-diameter oversize protection screen. The screen was fitted with a 48 Tyler mesh (295 μm) deck. The oversized material was discarded.

Coal-Water Slurry Storage and Handling System

A CWS storage and transfer system for use with the LSC-6 engine was designed, fabricated, tested and operated for almost three years. A schematic of the system is shown as Figure 2. The storage tank used is a modified tanker truck with a jet mixer to keep the slurry suspended. The heat generated from operation of the jet mixer is sufficient to keep the slurry above freezing temperatures in the winter. A control system was developed that automated the recirculation function, flushed the pumps to avoid CWS clogging, provided system diagnostics in the event of a failure, automated the refill of the engine day tank, and provided warning and safety signals for CWS loading into the tank.

A second CWS storage facility was designed, tested and operated at CQ Inc. This storage facility included two vertical, 5,000 gallon tanks, each stirred continuously with a low speed mixer.

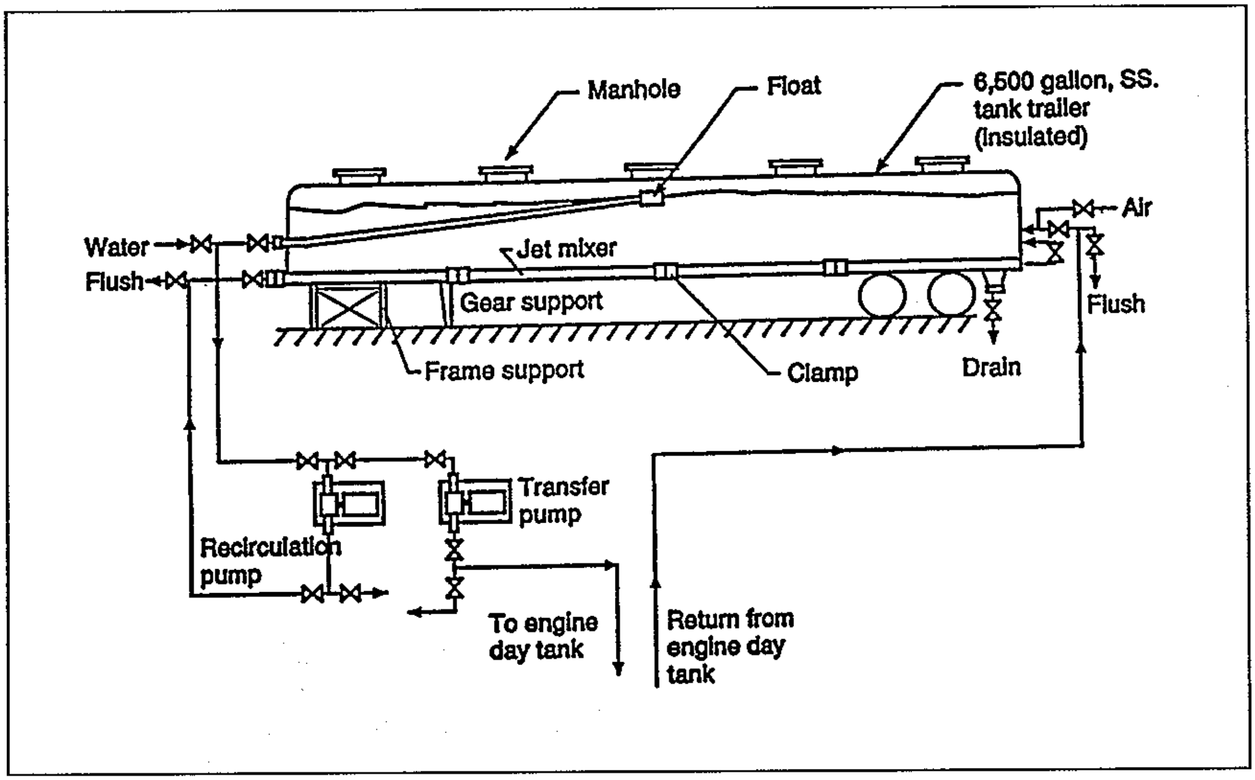

Figure 2: CWS Storage and Handling System

The jet mixing system can provide good mixing of the slurry and can maintain slurry solids content for periods of up to 6 months. The jet mixing system can keep the slurry above freezing even in the coldest winter months. However, the jet mixing system includes a pump which does require considerable maintenance. A low cost, low maintenance solution is to equip storage tanks with low shear stirrers. These tanks would have to be in a heated location to prevent freezing, or would need to be partially underground.

Engine Tests and Performance Results

Significant progress has been made in developing components for the coal-fueled diesel engine as part of the performance of this DOE contract. A total of more than 1050 hours of engine operation using coal-water slurry was logged on Cooper Bessemer engines as part of this program. Figure 3 illustrates the history of Cooper Bessemer test experience from 1987 to date. Advances in the durability of critical components such as the nozzle tip and piston rings have enabled Cooper Bessemer to accumulate hundreds of hours per year of engine test experience.

The LSC coal engine combustion system (including injector, pilot, and chamber shape) has been developed with special emphasis on:

- CWS fuel spray development and fuel-air mixing;
- Ignition and combustion of coal; and
- Durable power cylinder components.

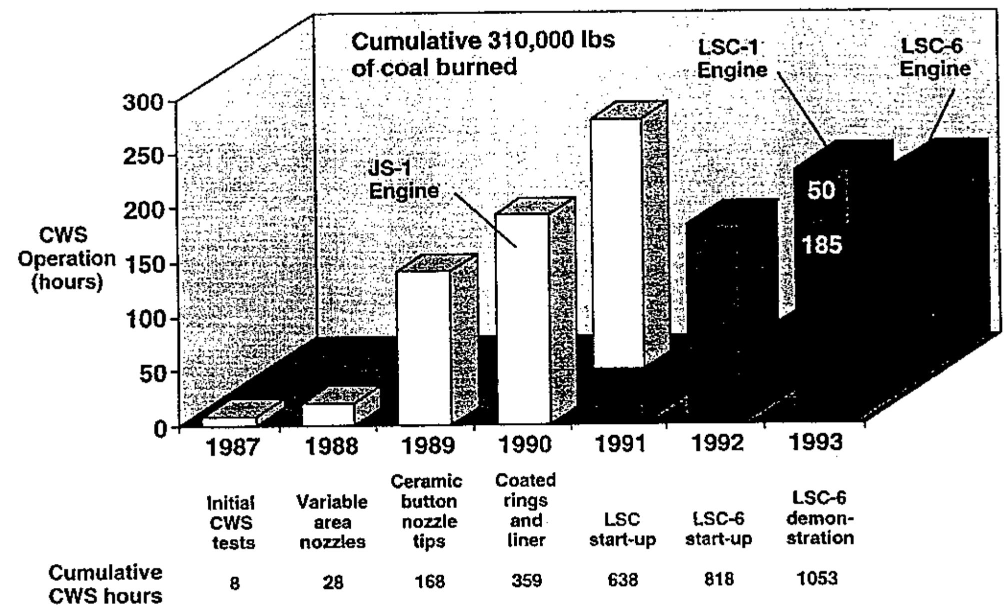

Figure 3: History of Engine Test Experience

The current 1800 kW prototype LSC system as implemented results in a CWS combustion process which is in many ways comparable to diesel combustion. High-speed visualization studies of slurry sprays, coupled with empirical evidence from engine experiments, suggest that the CWS fuel spray entrains sufficient air and coal volatiles to yield a combustible air/fuel mixture. Ignition is positive and repeatable using DF2 pilot injection in combination with a 10.6:1 compression ratio and 260°F intake air temperature. Modelling efforts by Texas A&M and Ricardo-ITI, as well as empirical data from Cooper Bessemer's sub-scale JS engine and full-scale LSC-1 engine tests have verified rapid coal combustion rates which rival DF2 or natural gas combustion rates (in a 400 rev/min engine). For example, Figure 4 shows a cylinder pressure trace from the LSC engine while operating on CWS at full speed (400 per/min) and full load (200 psi bmep). Note that the combustion event is essentially complete after only 30 degrees crank angle duration. New nozzle tip designs and durable coatings/materials have successfully been used to extend the useful life of critical in-cylinder components which have allowed hundreds of hours of successful engine testing.

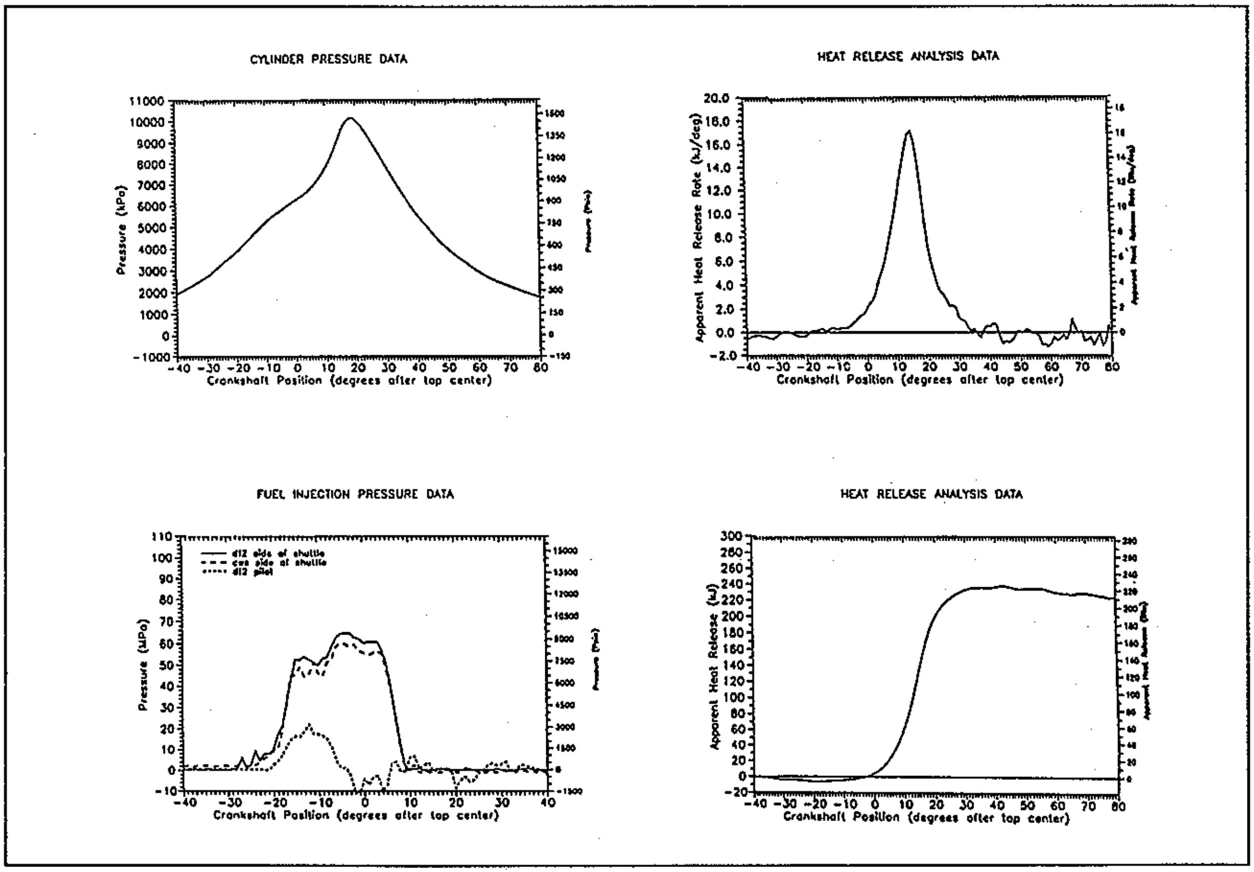

Figure 4: LSC Coal-Fueled Diesel Test Data Demonstrates Excellent Performance

Table 1 summarizes the test results of initial LSC-6 engine tests. All data was taken at full speed (400 rev/min) over a range of loads from 150 psi to 200 psi bmep. Peak firing pressure and exhaust temperature were well within design limits. The measured engine efficiency (6700 Btu/Bhp·hr) was considered to be excellent, exceeding our program goal. It is important to note that initial combustion optimization was conducted on the LSC-1 engine and that additional optimization was be undertaken on the LSC-6 engine. Table 1 also lists DF2 fuel performance data taken under the same operating conditions using the CWS injection system. Diesel performance with the engine configuration reoptimized for DF2 (nozzle hole size, injection timing, etc.) would be different.

	DF2 (Baseline)*	**CWS (Initial Results)**		
Speed (rev/min)	400	400	400	400
bmep (psi)	150	150	175	200
Power (bhp)	1,890	1,890	2,200	2,520
Peak Firing Pressure (psi)	1,320	900	1,400	1,600
Cylinder Exhaust Temp (°F)	930	870	890	920
Specific Fuel Consumption (Btu/bhp·hr)	7,300 (LHV)	7,500 (LHV) 7,800 (HHV)	6,750 (LHV) 7,050 (HHV)	6,700 (LHV) 7,000 (HHV)
NO_x (ppm) prior to SCR	1,180	594	852	1,020
CO (ppm)	2,100	300	-	-
CO_2 (%)	5.8	7.5	-	-
O_2 (%)	12.3	11.5	10.8	10.6

*Using CWS injection system (i.e. not optimized for diesel fuel)

Table 1: Initial LSC-6 Engine Performance Results

LSC-6 CWS Proof-of-Concept "Endurance Test"

In August 1993, the team of Cooper-Bessemer, ADL, AMBAC, and PSI successfully completed the world's first 100-hour "endurance" test with coal-water slurry on a full-scale 1.8 MW diesel engine with integrated emission control system. The test was started Monday, August 23, 1993, and the engine was run "around-the-clock" until the test was completed Saturday, August 28, 1993. Engine operation and performance were remarkably steady throughout the test. Approximately 200,000 lbs (22,000 gal) of CWS was consumed.

Overall engine performance results of this test matched previous full-scale LSC-6 test results and deviated very slightly during the 100-hour test duration. BSFC was excellent and was in the range of 6800 to 7000 Btu/bhp·hr (LHV). Cylinder exhaust temperature was normal and in the range of 900 to 910°F (average exhaust temperature of 6 cylinders). Peak cylinder pressure was typically 1200 to 1250 psi and occasionally went as high at 1300 to 1350 psi when individual cylinders would temporarily operate sub par until recovering (usually within a very short time). Emission rates were also as expected with NO_x ranging from 700 to 740 ppm at 11% O_2 (450 ppm at 15% O_2) during most of the test (this NO_x level is <u>upstream</u> of the SCR; actual NO_x stack emissions were much lower). Table 2 summarizes key operating conditions and performance results obtained from this test.

CWS Fuel	Baseline
Injection Configuration	Sapphire insert nozzle tips (new); 18x0.633 mm dia holes; 140 degree spray angle; 36mm injection pump; fast rate cam (LSC-16-1C)
Injection Timing	Nominal 18 BTC port closure
Pilot Configuration	Two DF2 pilot injectors per cylinder ($120mm^3$/stroke/injector)
Cyclone	Not present for this test; this provided wear data on technology
Speed	400 rev/min
Load	175 psi bmep
Power	2200 bhp
Peak Cylinder Pressure	1200 to 1300 psi
Cylinder Exhaust Temperature	900 to 910°F
Bsfc	6800 to 7000 Btu/bhp·hr (LHV)
NO_x(Engine out; prior to SCR) CO (Engine out) O_2(Engine out)	700 to 740 ppm 180 to 200 ppm 11.3 to 11.4%
Emission control system: NO_x and SO_x* Particulate Stack plume	 70 to 90% NO_x and SO_x reduction >99.9% reduction invisible

***Does not include NO_x and SO_x reduction resulting from coal cleaning step**

Table 2: LSC-6 Engine Performance During 100-Hour Proof-of-Concept Endurance Test

Emission Control System Design

Effective controls for NO_x, SO_x, and particulate emissions are essential for successful commercialization of stationary, Cooper-Bessemer, coal-fueled diesel engines. A major goal in the program was to establish the optimum emission control system from performance and cost perspectives and then to demonstrate the ability of this system to reduce pollutants to levels which will be required at 10 to 100 MW cogeneration and independent power production sites in the year 2000 to 2030 timeframe.

As part of this effort, PSI Technology Company (PSIT) and Arthur D. Little developed, installed, and tested an integrated engine Emission Control System (ECS) capable of treating the 1.8 MW engine's full exhaust flow (7700 scfm).

Engine Emissions and Control Targets

Emission measurements conducted during single-cylinder engine testing combined with coal-water slurry properties provided a sound basis for initially defining uncontrolled emission levels from full-scale, coal-fueled diesel engines. The emissions characteristics of the ECS are designed to be superior to those of larger, advanced, coal-power options. The projected levels and ECS performance targets are as follows:

Particulates: Commercially-viable, engine-grade, CWS is expected to contain 1 to 2 wt% ash (dry basis). Although this is much lower than the parent coal, particulate control devices are still necessary. With the demonstrated high engine combustion efficiency (99 to 99.5% carbon burnout), uncontrolled particulate emissions have been measured at about 1 to 3 lb/MMBtu. Achieving the coal-fired boiler New Source Performance Standard (NSPS) level of 0.05 lb/MMBtu requires a reduction of about 95 to 98%. In addition to air pollution considerations, particulate control is needed to protect the engine turbocharger from potentially severe wear.

SO_2: Engine-grade CWS has a sulfur content of about 0.7 to 1.5 wt% (dry basis), which yields SO_2 levels in the untreated engine exhaust gas of about 210 to 450 ppm at 11% O_2 (1.0 to 2.1 lb/MMBtu). We are conservatively using the NSPS for coal-fired utility boilers as a guideline and the overall required NSPS reduction for SO_2 is currently 90 or 70%, depending on the uncontrolled emission level. Considering the low sulfur content of engine-grade CWS and the relatively small powerplant capacity of expected engine installations, 70% reduction of SO_2 in the exhaust gas has been chosen as a reasonable target.

NO_x: Measured emissions of NO_x from the coal-fueled engine are about half those of conventional diesel engines, due in part to the flame temperature suppression effect of water in the slurry. Measured coal-fueled diesel NO_x emission levels of 600 ±200 ppm at 11% O_2 (1.8 ± 0.6 lb/MMBtu) must be significantly reduced to make the Cooper-Bessemer engine

commercially viable. For example, a reduction of 50 to 75% would be necessary to meet the NSPS coal-fired utility boiler standard of 0.6 lb/MMBtu. However, recognizing that state and local regulations are often more stringent, and that future NSPS may tighten to the level of low-NO_x burners (0.3 lb/MMBtu), our control system is designed to achieve 80% NO_x reduction. Furthermore, it incorporates Selective Catalytic Reduction (SCR), a control method considered Best Available Control Technology (BACT) by many regulatory agencies.

CO and Unburned Hydrocarbon Emissions: The combustion characteristics of the CWS fuel in the Cooper-Bessemer engine have been excellent. Carbon monoxide and unburned hydrocarbon emissions are low, in the ranges of 100-300 ppm and 20-200 ppm, respectively. As a result, control methods for these pollutants are not necessary.

Integrated Coal-Diesel Emissions Control System (ECS)

The ECS designed for Cooper-Bessemer's 1.8 MWe coal-fueled engine is comprised of the following eight subsystems: in-cylinder NO_x reduction, cyclone, SCR reactor, heat exchanger, sorbent injection, baghouse, induced draft (ID) fan, and flue gas sample conditioning and analysis. Figure 5 provides a layout of the ECS. In operation, exhaust gas from the engine first enters the cyclone where relatively large particulate matter is removed to protect the engine's tubocharger. Gas exiting the cyclone goes to the turbocharger where the temperature and pressure are reduced to about 800-850°F and 20 in. w.c., respectively. The first subsystem in the ECS is the SCR reactor where NO_x is reduced by about 80%. Then the gas enters a water-cooled heat exchanger which reduces the gas temperature from 800-850 to 350°F, simulating a heat recovery steam generator. After the heat exchanger, sorbent is injected into the flue gas in a mixing venturi, reducing SO_2 by about 70%. The exhaust gas and sorbent mixture enters the baghouse where the spent sorbent is removed from the flue gas. After the baghouse the clean exhaust gas flows through the ID fan and to the stack. The ECS control room is located central to the major components of the ECS and contains the flue gas analysis system, datalogger and control panels for the ECS subsystems. From this room operators can control and monitor the performance of all of the subsystems in the ECS.

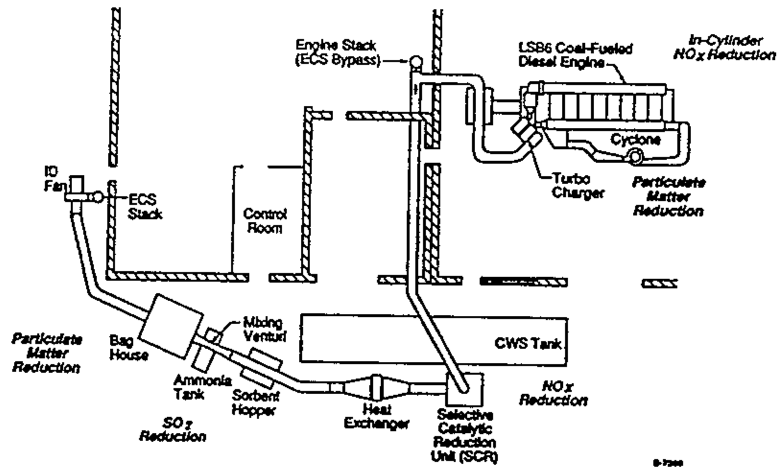

Figure 5: Layout of the Emissions Control System for 1.8 MWe Cooper-Bessemer Engine in Mt. Vernon, Ohio

The final steady state emissions from the ECS system are shown below in Table 3:

Stack Emission	ECS Performance Vs. Goal
0.35 lb/MBtu NO_x	Actual 80% vs. 80% goal
0.08 lb/MBtu SO_2	Actual 90% vs. 70% goal
0.003 lb/MBtu Particulate Matter	Actual 99.9-99.98% vs. 99.5% goal

Table 3: ECS Performance

Both the sorbent injection and baghouse systems exceeded their performance goals by substantial margins. The SCR system exceeded its goal initially; but interactions with effluents from coal combustion and operation below the design temperature range resulted in performance at the end of testing that was closer to the goal. SCR performance can be improved by catalyst reformulation, but this identifies the need to accurately know the engine exhaust temperature over the load range. The cyclone is the only system which did not perform adequately. Unfortunately, the cyclone was unable to capture any significant amount of particulate matter, probably due to the pulsing characteristics of the diesel engine exhaust flow. However, a recently completed physical modelling study has identified cyclone and exhaust duct modifications that should yield the particulate removal performance required to protect the engine's turbocharger.

DEVELOPMENT STATUS AND PLANNED FIELD DEMONSTRATION (CCT-V PROJECT)

The commercialization plan for the coal-diesel technology has been based on the results of the 100-hour system demonstration test at Cooper-Bessemer. The key practical implications of the tests are as follows:

(1) Test results show that the technology met both the efficiency target and the emissions targets, and performance in these areas did not degrade during the 100-hour test. We conclude that efficiency and emissions improvements areas <u>are not on the critical path</u>; straightforward engineering effort can achieve scale-up of the engine and emission system to commercial plant sizes.

(2) Longer run times <u>are</u> needed to estimate useful lifetimes of certain engine components, particularly the useful life of piston rings and exhaust valves. <u>This data on engine components is critical before commercial introduction of the technology</u>. Engineering solutions and material selections are available for durable components, but these solutions must be optimized and demonstrated for several thousand hours, not several hundred hours as has been accomplished so far.

(3) The CCTV program recently initiated by Cooper/Arthur D. Little is a field demonstration program that will provide 5,000 - 10,000 hours of engine run time on coal fuel. Since this will require four years of testing, the implication is that commercial introduction (plant orders) can be targeted in the 2000 - 2005 timeframe (assuming a successful field demonstration).

(4) Coal-slurry fuel is expected to become competitive in the U.S. with diesel oil and natural gas in the 2000 - 2005 timeframe, based on energy price projections made by DOE and others. This gives Cooper-Bessemer and other team members the necessary time to optimize and demonstrate the wear solutions for critical hard parts, through a field demonstration program of 5000 - 10,000 hours.

(5) Field demonstration opportunities for small coal-diesel plants will be pursued in special situations where clean-coal fuel holds a price advantage, such as:

- Alaska rural electrification (where diesel oil costs $4 - $12 per million Btu delivered to certain remote communities).
- China, which has both coal reserves and the need for rapid installation of non-grid power (such as diesels).
- Eastern Europe, which also has coal reserves and is undergoing rebuilding of the electric power infrastructure in a manner to greatly reduce emissions.

(6) Test experience has shown that the capital cost of the coal-diesel plant will not be a problem. The cost of all equipment modules for the plant has been established, and the installed plant cost estimates appear to be competitive:

- $1600/kW for early demonstration plants
- $1300/kW for mature plants

These costs are well below the capital cost of other small coal plants.

(7) Test results established the coal-water fuel specification, and proved that a wide range of coals can be utilized to prepare engine-grade slurry. The cost of the fuel will be under $3.00/MMBtu once adequate fuel demand exists in a given region. The commercialization plan incorporates a series of steps to build up an "infrastructure" for coal-water slurry production and distribution. <u>This is recognized as critical.</u>

HEALY CLEAN COAL PROJECT: FABRICATION AND CONSTRUCTION STATUS

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ABSTRACT

The Healy Clean Coal Project, selected by the U.S. Department of Energy under Round III of the Clean Coal Technology Program is currently in the procurement and construction phase. Construction is scheduled to be completed in 1997. The project is well under way to initial operation in 1998. After more than five years of planning, design and permitting activities, the project celebrated its ground-breaking ceremony at Healy, Alaska on May 30, 1995. This project is a major step in the commercialization of TRW's slagging coal combustion technology which is the focus of this demonstration project. Two 350 million Btu/hr coal combustors and the associated coal and limestone feed systems are being fabricated, and will be delivered to the site in 1996. The project status, its participants, description of the TRW technology, and the operational and performance goals of this project are presented here. In conjunction with a back-end spray dryer absorber system, the emission levels of NO_x and SO_2 and particulates of this 50 megawatt plant are expected to be significantly lower than current standards. The project is owned and financed by Alaska Industrial Development and Export Authority (AIDEA), and is cofunded by the U.S. Department of Energy.

1. INTRODUCTION

More than five years of planning and permitting culminated in spring 1995 with start of construction on the Healy Clean Coal Project (HCCP). The ground-breaking ceremony of this plant was celebrated on May 30, 1995. During the summer 1995, earthwork, foundation and structural steel work will be undertaken with construction and erection of all equipment slated to continue through late 1997. Operation is scheduled to begin in 1998.

Construction will employ an estimated average of 200 workers over two years, with the permanent addition of 35 to 40 new jobs in Healy, a small town about 80 miles southwest of Fairbanks, Alaska. Construction impacts on the community will be minimized through use of a construction camp where workers will live. Efforts to maximize local hire opportunities are being initiated.

AIDEA will finance and own the facility, the U.S. Department of Energy contributing approximately $117.3 million. The project consists of a 50-megawatt power plant which uses TRW slagging coal combustion systems that burn Alaska low grade coal in staged combustion to minimize air pollution. The project uses a conventional boiler that produces steam for a conventional turbine to produce up to 50 megawatts of electricity for use by the Fairbanks-based Golden Valley Electric Association (GVEA).

The clean coal facility will be built near the Usibelli Coal Mine to save coal freighting costs and will be adjacent to GVEA's existing 25 megawatt coal-fired plant, which was built in Healy in 1967.

The HCCP will help augment the current capacity of GVEA, whose service area continues to see increased demand.

Figure 1 illustrates a simplified system overview. The plant is designed for burning an inferior waste coal containing 22% ash (moisture-free basis).

The performance goals of this project are to demonstrate lower emissions of NO_x, SO_2 and particulate matter than those required by the New Source Performance Standards as given below, while burning low grade, high-ash Alaskan waste coals:

NO_x emissions	0.2 lb/million BTU (0.36 kg/million kcal)
SO_2 emissions	10% uncontrolled emissions

Particulate Matter ($\leq 10\ \mu$)   0.015 lb/million BTU (0.027 kg/million kcal)

The project is structured in three phases: Phase 1, Project Definition and Design; Phase 2, Procurement and Construction; and Phase 3, Operation. Phase 1 has been completed, and the fabrication of the equipment and construction on the site are currently in progress.

The HCCP is estimated to cost $267 million and will be funded as follows: $117.3 million from the U.S. Department of Energy; $25 million Alaska state grant appropriated in 1990; $69.6 million advance funding by AIDEA; $29.2 million in interest earnings; and $15.1 million in power revenues. It should be noted that these project costs are significantly higher than the projected cost of the next commercial unit because (1) the HCCP is a first-of-a-kind unit with a major fraction of the cost related to design and development of a unit which has never been built before, (2) the seismic design requirements in Alaska are very stringent and (3) the construction costs in this remote part of Alaska are very high. The U.S. Department of Energy is cost-sharing this project as part of its commitment to the commercialization of clean coal technologies, especially those that offer major reductions in emissions such as NO_x, SO_2 and particulates.

Figure 2 is a photograph of the construction site, showing the initial pouring of concrete for the foundation; in the background is the existing 25 megawatt Healy Unit No. 1.

Two Synergistic Technologies

Burning of coal typically creates oxides of sulfur and nitrogen that can result in air pollution and acid rain. The HCCP integrates two advanced technologies designed to reduce the emission of these pollutants. It offers other benefits as well, in that coal not well suited for export can be utilized rather than wasted, and byproducts from the combustion process are non-polluting and potentially useful.

The first innovative process is TRW's slagging coal combustion system that burns coal in staged combustion to minimize the formation of nitrogen oxides. The combustion system melts and removes the ash contaminants in the coal as slag.

Pulverized limestone is injected at the combustor-boiler interface for sulfur dioxide control. The limestone is converted by heat in the flue gas to lime, which reacts with the sulfur dioxide in the gas and removes it as sulfate. The unreacted lime and sulfates are caught by the second new technology, a spray-dryer absorber system, supplied by Joy Environmental Technologies, Inc., and recycled to scrub the flue gas and further reduce the sulfur dioxide content.

The combustion systems provide hot gaseous products to a conventional boiler that produces steam for a conventional turbine to produce 50 megawatts of electricity for use by GVEA.

The two TRW combustors are designed to fire the boiler from the bottom upwards as shown diagrammatically in Figure 1. An isometric view of the boiler and combustion system used in the HCCP is shown in Figure 3. For each combustor, crushed coal, stored in a silo, discharges into a pulverizer via a coal feeder/weighing scale. The pulverized coal with its carrier or primary air from the pulverizer is boosted in pressure to 60 inches of water (gauge) (1.15 atm) by the mill exhauster fan. This pressure is necessary to overcome the pressure drop through a non-storage coal feed/splitter subsystem which enables the coal to be split and fed into the precombustor and slagging stage. The coal feed/splitter subsystem also separates a major portion of the primary air and diverts this air to NO_x ports; this helps in reducing the amount of cold air going into the combustor, thereby increasing the temperature and reducing NO_x for any fixed stoichiometry.

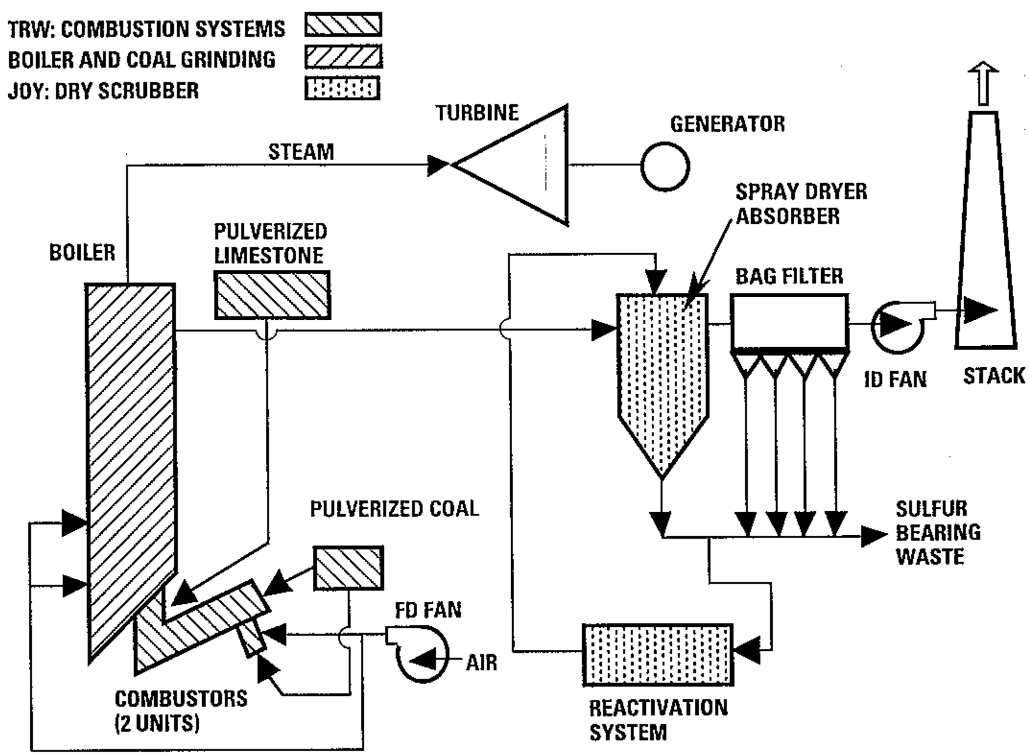

Figure 1. Healy Clean Coal Project System Overview

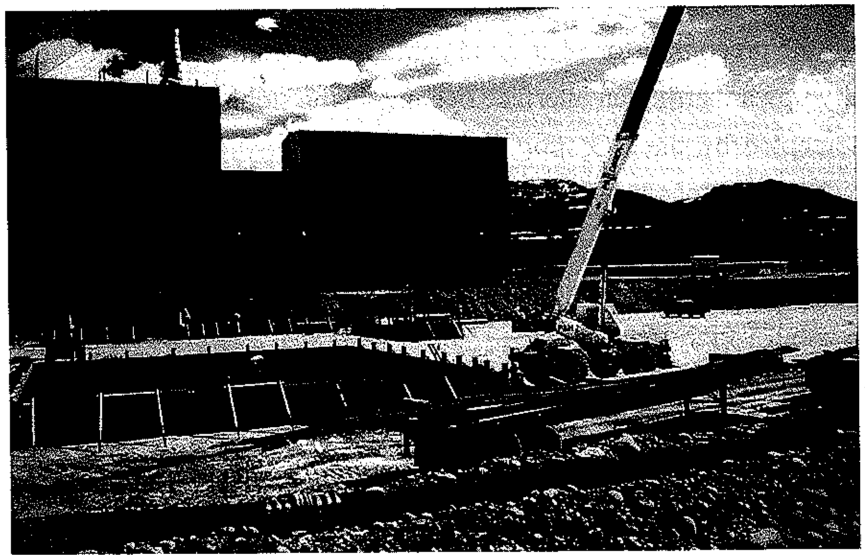

Figure 2. HCCP Construction Site, May 1995

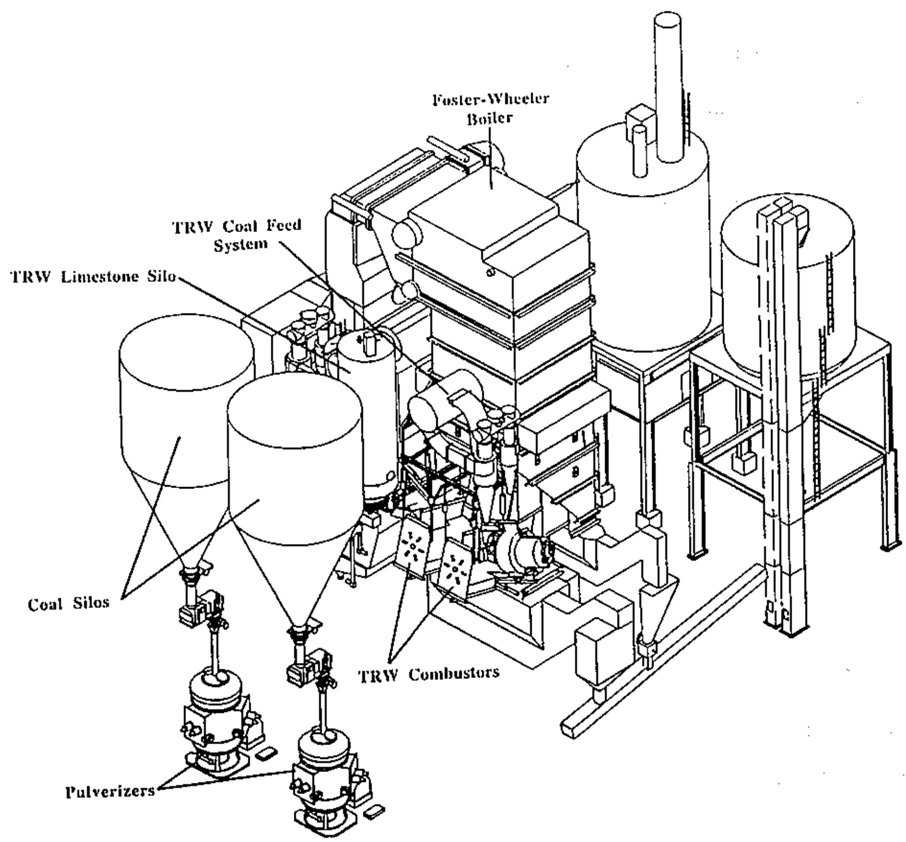

Figure 3. Isometric View of the Boiler and Combustion System

The slagging stage portion of the coal is further split into six parts and injected into the head-end of the slagging stage via six injection ports. The precombustor portion of the coal is fed to the coal burner section of the precombustor. The combustion gases from the slag recovery section enter the furnace vertically upwards from an interface opening in the sloping bottom of the furnace. This jet or flame is intercepted by the NO_x port air. Optional over-fire-air can also be introduced for supplemental NO_x and temperature control.

A single limestone feed subsystem services both combustors. Pulverized limestone, stored in a silo, discharges via a weigh scale feeder to an air-lock and a two-way splitter. A separate air-driven eductor is used at each leg of the splitter to transport the limestone-air mixture to the single limestone injector located on the side of the slag recovery section. The limestone particles flash-calcine to lime by the time they reach the backpasses of the boiler. These particles are collected and utilized by the Joy spray-dryer absorber system to remove over 90% of the SO_2 in the combustion products. Final particulate control is accomplished in the baghouse.

Benefits to U.S. and Pacific Rim Countries

The HCCP brings more than $117 million in federal funds into Alaska and brings together state and federal government agencies in partnership with the private sector.

The project will bring economic diversification and growth to the Alaska Railbelt. It will also create additional energy generation to serve interior Alaska. The Fort Knox gold mine, currently under development near Fairbanks, will add 35 megawatts to GVEA's energy demand, which is approximately 70% of the Healy Clean Coal Project's 50-megawatt output. The project will augment the capabilities of the existing power plant, which was constructed in 1967 and will provide a reliable source of power to GVEA customers and minimize complications related to the growing demand on the current aging facility.

Coal is one of Alaska's abundant natural resources. The HCCP provides Alaska with an opportunity to demonstrate two new technologies that will help solve the international problem of acid rain. TRW's slagging coal combustion technology will be ready for widespread commercialization in the late 1990s and will have great potential for reducing acid rain from new and retrofitted plants in the world. The technology will be American owned and highly competitive in the international market.

The project will demonstrate to markets in the lower 48 states of the U.S.A. and abroad the attractiveness of Alaska coal used in combination with TRW's advanced combustion technology. The project will enhance the export potential of Alaska coal by attracting international attention, thereby helping spur efforts to market this abundant resource. Alaska has the opportunity to develop a significant coal export industry because the rapidly developing economies in the Pacific Rim are seeking low-sulfur coals to meet their power needs and increasingly stringent air quality standards.

The HCCP Team

AIDEA

The Alaska Industrial Development and Export Authority will own and finance the project; administer state funds; and perform as the participant under the U.S. Department of Energy cooperative agreement.

U.S. Department of Energy

Originated the nationwide Clean Coal Technology Program and awarded the Healy Clean Coal Project, one of only 13 project selected from among 48 proposals, under Round III of Clean Coal Technology Program.

GVEA

Golden Valley Electric Association will operate the facility under an agreement with AIDEA and pay for power generated under terms of a power sales agreement.

TRW Space & Technology Division

Designed and will supply one of the project's new technologies, the slagging coal combustion system. TRW's major subcontractors include Foster Wheeler, Delta-Ducon and VibraScrew.

Joy Environmental Technologies, Inc.

Designed and will supply the project's other new technology being tested, viz, the flue gas desulfurization system.

Foster Wheeler Energy Company

Will fabricate and supply the boiler systems.

Stone and Webster Engineering Corporation
Architect/engineer for the project.

Usibelli Coal Mine, Inc.
Will furnish coal under a supply agreement with Golden Valley Electric Association.

H.C. Price
H.C. Price company will provide the general construction services.

2. TRW SLAGGING COAL COMBUSTION SYSTEM

System Description

Figure 4 illustrates an isometric view of a 350 MMBtu/hr TRW (88 million kcal/hr) slagging combustor designed for the HCCP. It consists of a precombustor, a slagging stage and a slag recovery section. The precombustor is used to boost the combustion air temperature from the air heater (typically 260°C to 370°C) to 1100°C to 1375°C by burning 30 to 40% of the pulverized coal in two stages. In the first burner section, coal is burned at stoichiometries (actual air/theoretical air) of 0.8 to 1.0 followed by a mixing section where the remaining air is added resulting in stoichiometries over 2.0 at the exit of the precombustor. This process produces hot vitiated air without allowing the ash in the coal to either slag or foul the insides of the precombustor.

The precombustor is a vital component of the system because it prevents slag freezing within the slagging stage during operation under substoichiometric conditions even for coals having high ash fusion temperatures, and it stabilizes combustion over a wide range of coal moisture and volatile contents and slagging stage stoichiometry. Low volatile coals can be accommodated by firing a larger portion of the coal in the precombustor.

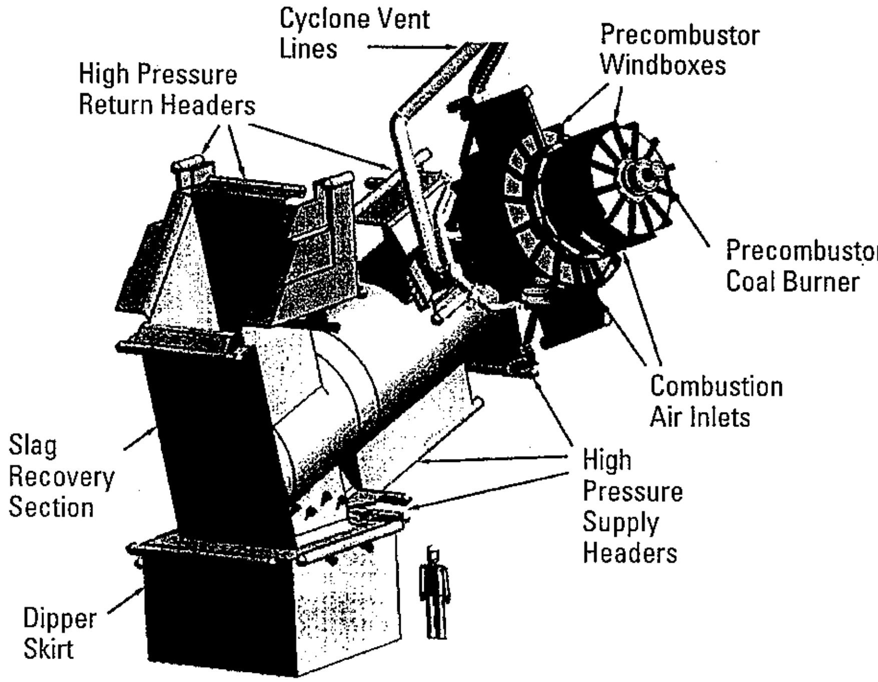

Figure 4. Isometric View of the Healy Clean Coal Combustor

The high temperature, oxygen-rich combustion gases from the precombustor enter the slagging stage tangentially, generating a highly turbulent, confined vortex flow. The balance of the pulverized coal (60 to 70%) is injected through a multiport injector at the head end of the slagging stage. The high air preheat temperature promotes a hot slagged surface on the interior of the slagging stage, which combined with the strong recirculation patterns, ensures stable ignition and combustion. The multiport injector helps distribute the coal evenly for better coal/air mixing and combustion. The slagging stage is operated at substoichiometric conditions typically in the range 0.75 to 0.9. Carbon conversion to gases is maximized and NO_x emissions are minimized by controlling the mixing and stoichiometric conditions in the slagging stage.

The slagging stage and the slag recovery section are operated in a slagging mode, i.e., the ash melts to form a molten slag layer which coats the inside surfaces. Operating temperatures within the slagging stage are high enough that the majority of the ash in the coal particles melts and fuses in-flight. The resultant molten ash droplets are centrifuged to the walls of the slagging stage, forming a self-replenishing slag layer. This layer protects the water-cooled metal body of the combustor from erosion, abrasion and corrosion, and reduces the heat transferred to the water in the combustor body. The molten slag is transported along the walls by shear and gravity forces.

The water-cooling circuits can be designed to be either drainable or non-drainable. The heat absorbed by the cooling water is recovered either by integrating it with the boiler feed water system or by a separate high-pressure system with a flash tank for generating additional steam. The exact choice of cooling water integration is invariably site-specific. In the HCCP the cooling water is directly integrated with the water in the steam drum through a separate forced-circulation circuit.

A washer-shaped baffle with a key-slot in the 6 o'clock position separates the slagging stage from the slag recovery section. The slag flows through the key slot, along the bottom to the slag tap opening located in the slag recovery section. The slag recovery section is larger than the slagging stage to reduce flow velocities, which in turn prevent shearing of the slag up to the furnace opening. Up to 90% of the slag is tapped through the slag tap by gravity. The dipper-skirt provides a water seal and the molten slag quenches and shatters upon dropping into the water. The solidified, vitreous slag is removed from the quench water tank by a drag chain conveyer. Hence, only the slag not tapped enters the furnace. Because of the aerodynamics of slag separation, the majority of this slag will be fused particles of less than 10 microns in size; such particles are significantly less fouling and erosive than conventional fly ash particles thereby increasing the life of the furnace and its convective tubes.

Figures 5 and 6 show photographs of the combustor in fabrication at the manufacturing facility of TRW's major subcontractor, Foster Wheeler. Figure 5 shows a view of the right-sidewall of the slag recovery section after completion of welding, bending and header installation. Figure 6 shows the cylindrical portion of the left sidewall of the slag recovery section after completion of tube-to-fin welding.

An innovative non-storage-type direct coal feed system has been designed by TRW and is being fabricated by TRW's subcontractor, Delta-Ducon. The major components of the pulverized limestone feed system is being fabricated by TRW's subcontractor, VibraScrew. The fabrication of TRW's scope of supply is expected to be completed by mid 1996.

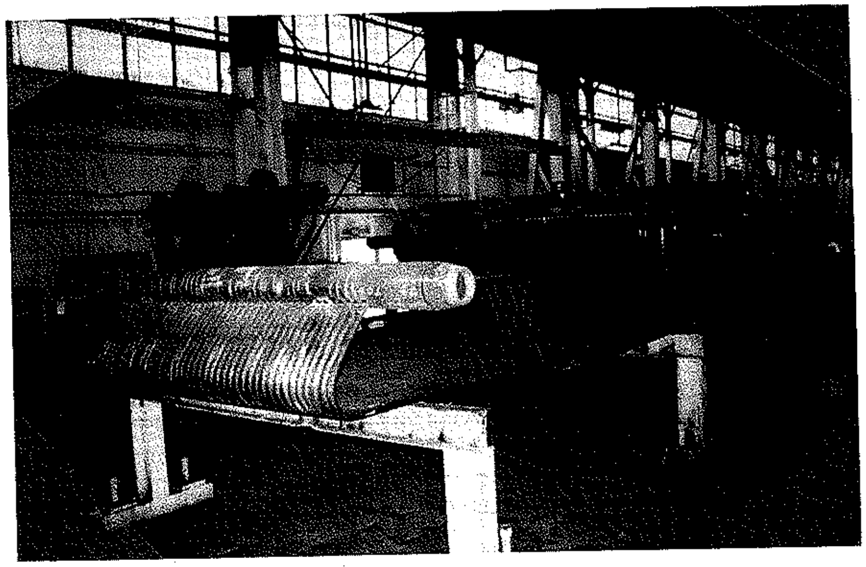

Figure 5. Right Side Wall of the Slag Recovery Section

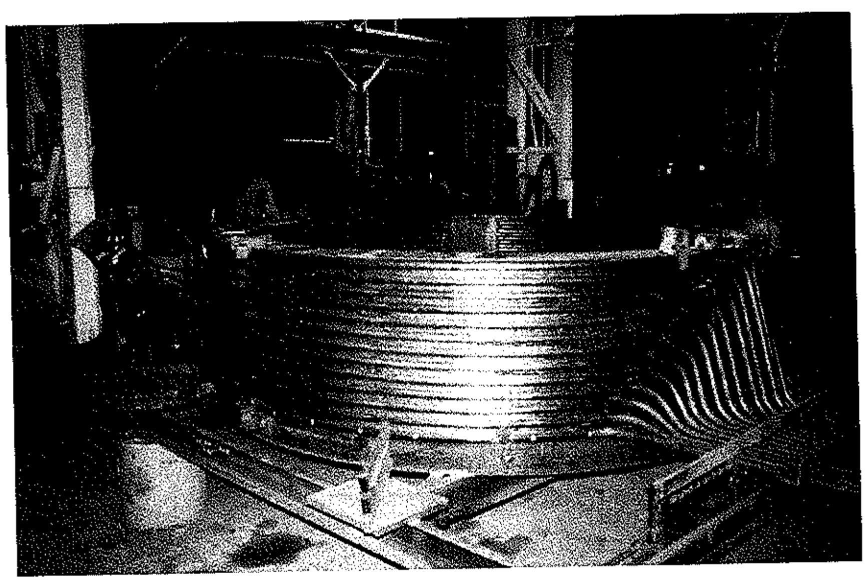

Figure 6. Cylindrical Portion of the Slag Recovery Section

Emissions Control

Figure 7 represents the coal and air flows in a typical slagging combustor application in a block diagram format. The NO_x emissions are minimized by a combination of coal and air staging which supports the basic processes shown below.

	In the Slagging Stage (Fuel-Rich)	In the Furnace (Fuel-Lean)
NO_x is lower when:	Temperature is higher	Temperature is lower
	Stoichiometry* is lower, up to a minimum of ~ 0.75	Stoichiometry* is lower (in the range of 1.0 to 1.3)

* Actual air/theoretical air

In the slagging stage, higher temperature is achieved by preheating the combustion air in the air heater to as high a value as possible, and the stoichiometry is reduced to as low a level as possible without compromising on slagging and carbon conversion.

As the combustion gases enter the furnace, the stoichiometry is still less than unity. The remaining air is added in the furnace either at the NO_x ports or at the over-fire-air ports to complete the combustion at an overall stoichiometry of 1.1 to 1.2 (10 to 20% excess air).

In the furnace, the addition of final air is delayed until the gas temperature is reduced by radiative cooling to the walls; this reduces the peak temperatures in the furnace. Also, excess air in the range 10 to 20% is maintained not only to reduce NO_x but also to improve the combustion of any unburned carbon in the gases.

For mitigation of SO_2 emissions, the combustor offers the advantage of *in-situ* calcination of pulverized limestone ($CaCO_3$) which is injected in the upper region of the slag recovery section. The limestone particles are calcined in the furnace to highly reactive flash-calcined lime (CaO) particles. By the time these lime particles mix and move with the combustion products to the exit of the boiler, a significant portion of the SO_2 is absorbed to form gypsum ($CaSO_4$). In the HCCP the utilization of these flash-calcined lime particles is enhanced by a back end spray-dryer-absorber system specifically designed by Joy Technologies Inc. Over 90% SO_2 removal is anticipated with this system at calcium-to-sulfur ratio of 1.1 to 1.8. The Joy system also includes a baghouse which removes most of the particulate matter to well below New Source Performance Standards. Even without the Joy system, up to 70% SO_2 removal is possible at calcium-to-sulfur ratio > 3.

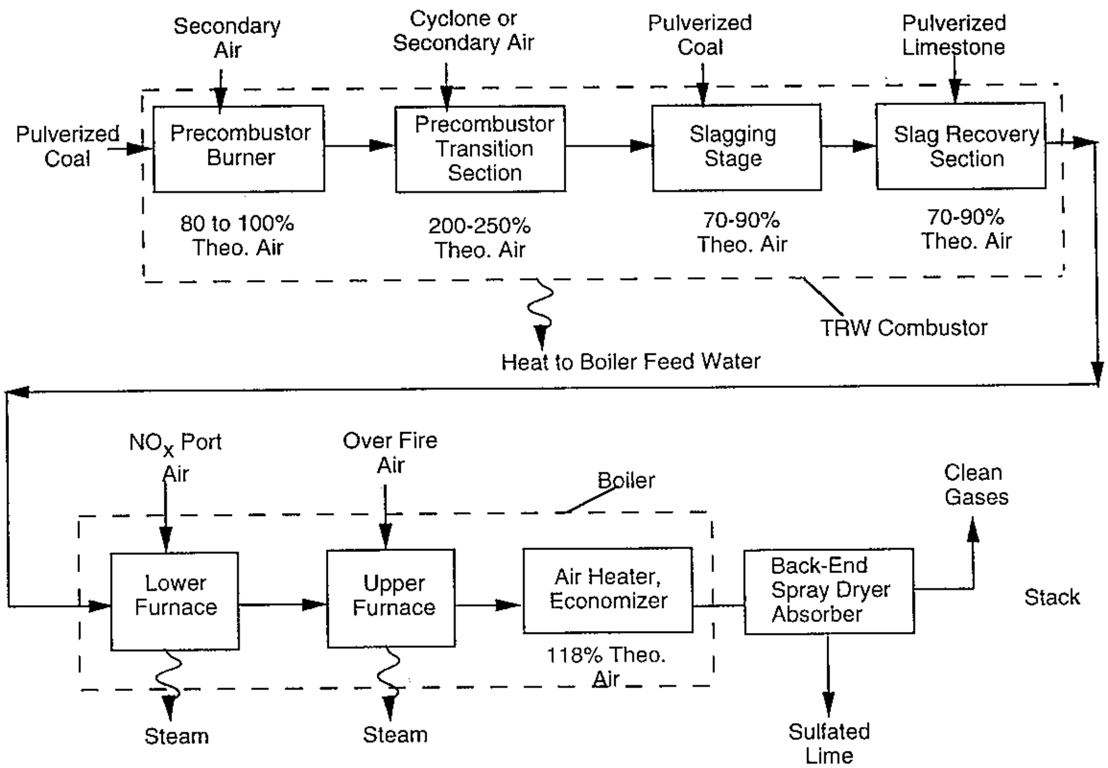

Figure 7. Coal and Air Flows in the Healy Clean Coal Project

3. TECHNOLOGY EDGE

For utility power generation, coal is burned in chunks, crushed form or pulverized (powdered) form, as shown in Figure 8. Fluidized beds, low NO_x burners and slagging combustors are advanced technologies which produce significantly lower primary air pollutants than the first generation of combustion technologies. Post-combustion systems for scrubbing primary pollutants are also available today. For NO_x control, the technologies are: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Fuel reburning is also a means of controlling NO_x. For SO_2 control, the technologies are wet and dry flue-gas desulfurization (FGD) systems. Most FGD systems use lime (CaO) as the sorbent. The dust emissions in all systems are controlled by either baghouses or electrostatic precipitators. There are also specialized technologies (e.g., NOXSO process) which reduce both NO_x and SO_2 emissions simultaneously using special sorbents. In the utility industry, invariably a combination of two or more of these technologies is used to meet site-specific emissions requirements.

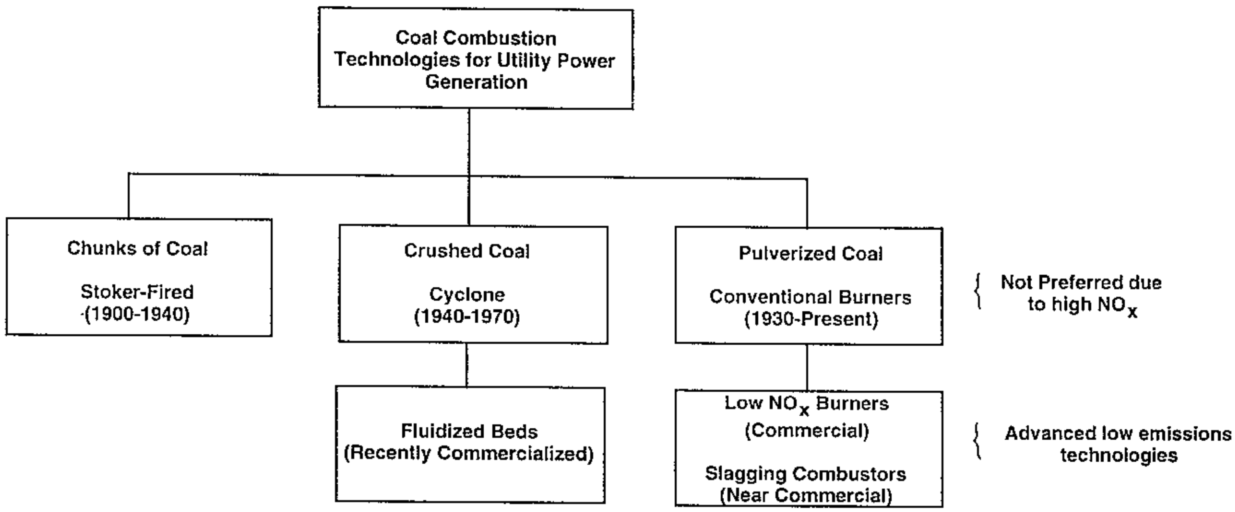

Figure 8. Coal Combustion Technologies

Typical problems encountered in coal-fired power plants are:

- Difficulty in burning very low volatiles coals (anthracite)
  - Low volatiles content of 5 to 8% dry, ash-free
  - Coal can only be combusted with large, continuous gas addition of up to 30%
  - Need gas lances to keep slagging furnace bottom open

- Difficulty in burning low grade, high ash coals (off design coals)
  - High ash content to up 40%
  - Reduced energy content (6,480 BTU/lb or 3600 kcal/kg)
  - Broad range of ash fusion temperatures (2000^0F to 2900^0F or 1100^0C to 1600^0C)
  - Boiler fouling and lower power production
  - Coal feed system and furnace size limits
  - Gas assist of up to 25% to make up for reduced output from the original low-ash boiler design

- Power short-falls exist today in many countries:
  - Oil or gas import for power generation cannot be economically justified
  - Boilers are getting older and have to be replace or upgraded (retrofits)
  - Population is against nuclear power

- Difficulty in complying with emissions standards:
  - High sulfur coals causing high SO_2 emissions
  - High NO_x emissions
  - High particulates in stack gases

TRW slagging coal combustion systems offer the capability of burning a wide variety of coals from very low volatiles coals to low grade, high ash coals. The TRW coal combustion system:

- Eliminates the need for oil or gas assist

- Increases the boiler's combustion efficiency

- Decreases plant fuel costs by replacing oil with coal

- Reduces the emission of pollutants (SO_2, NO_x and particulates)

- Provides a usable, environmentally neutral, by-product (slag) and significantly reduces waste disposal problems (ash)

- Can be used to retrofit many types and sizes of existing boilers

- Offers high turn-down capability (3 to 1)

- Reduces erosion, slagging and fouling of furnace, convective pass and superheat tubes even when burning high ash coals and, hence, reduces boiler maintenance and downtime.

TRW owns five U.S. patents (see References) and several foreign patents which describe in detail all the technical features summarized above.

4. COMPETITIVE EDGE

The HCCP is the first utility-size demonstration of TRW's slagging coal combustion system and its synergy with Joy's spray-dryer-absorber back-end scrubbing system. In addition to meeting the performance goals cited earlier, another important goal of the HCCP is to pave the way for the commercialization of the new technologies. The commercial success of this technology depends heavily on a higher performance-to-cost ratio than competitive technologies.

Figure 9 compares the HCCP technology qualitatively with major competing technologies in the clean coal combustion market. In this figure "retrofit" is defined as the integration of new components into an existing boiler plant, and the comparisons are benchmarked against standard pulverized coal units.

A discussion on each of the evaluation criteria is given below:

Retention of Existing Boiler

- The TRW technology, the low NO_x burners and reburning technologies are amendable to retrofit of existing boilers without any modifications to the boiler steel and, hence, can be accomplished at relatively low cost.

- In general, fluidized bed technology requires removal of the existing boiler island in order to install the bed. In some specific sites, it is possible to convert an existing pulverized coal boiler to a fluidized bed by replacing the bottom half of the furnace while retaining the top half. Even in this case it would be necessary to make fairly extensive modifications to the boiler which result in much longer plant downtime and significantly higher cost.

EVALUATION CRITERIA WITH RESPECT TO STANDARD P.C. BOILERS		TRW System With Joy-Niro Back End System	Low NO_x Burners With Conventional Back End Flue-Gas-Desulfurization	Fluidized Bed System	Back End NO_x Scrubbing System	Reburning In Furnace With Conventional Back End Flue-Gas-Desulfurization
RETROFIT ONLY	Retention of Existing Boiler	Yes	Yes	Some parts of boiler need significant modification or replacement	Yes	Yes
	Conversion of Oil/Gas Units to Coal	Yes	No	No	No	No
	Restoration of Plant Capacity	Yes	No	Yes, depending on the extent of boiler modifications	No Impact	No
RETROFIT AND NEW UNITS	Impact on Unburned Carbon Loss	Lower Carbon Losses	No Impact	Higher carbon losses	No Impact	Higher carbon losses
	Reduction of NO_x	Yes	Yes	Yes	Yes	Yes
	Reduction of SO_2	Yes	Yes	Yes	No	Yes
	Reduction of PM-10	Yes*	Yes*	Yes*	Yes*	Yes*
	Impact on Tube Erosion and Fouling	Lower	No Impact	Higher	No Impact	Higher
	Fuel Flexibility	Yes	Yes	Not all coals; cannot burn low ash-fusion coals	Not Applicabl e	Not Applicable
	Power Requirement	Higher (Combustion Air, exhauster, circulating pump)	No Impact	Power required for higher pressure combustion air offsets pulverizer power saved	No Impact	Higher
	Recovery of Heat in Fly Ash and Slag	Heat in Slag Is Not Recovered	No Impact	Heat in discharged bed material is recoverable	No Impact	No Impact

* Accomplished by integrating venturi scrubbers, baghouses or electrostatic precipitators in the systems

Figure 9. Comparison with Competitive Systems

Conversion of Oil/Gas Units

The slagging coal combustion technology is the only technology which could be used to convert an existing oil or gas fired unit to coal by virtue of the fact that it removes most of the ash in the coal before the combustion products enter the furnace. A retrofit of this type is possible only in plants where there is adequate space around the boiler to accommodate the combustors. None of the other technologies offer this advantage.

Restoration of Plant Capacity

In order to restore the design plant capacity, the amount of particulate carryover into the boiler must be reduced.

- The combustor removes greater than 80% of the coal ash material as molten slag prior to the boiler furnace. Since less than 20% of the coal ash enters the boiler, derating is not required even during operation with high ash coals.

- Low NO_x pulverized coal burners do not remove any of the coal ash prior to the boiler and, hence, require derating during operation with high ash coals. Derate penalties as high as 20% are common.

- For fluidized bed combustors, the majority of the ash (typically 80%) is carried over into the boiler convective passes and superheater section and can result in slagging or fouling. Derating of the system may be required during operation with high ash coals. Internal recirculation of the particulates within the furnace itself (in order to limit particulate carryover into the convective passes and superheater section) is still under development.

Impact on Unburned Carbon Loss

- In the TRW system, because of combustion of coal prior to entering the furnace, any unburned carbon from the combustor still has the residence time in the entire furnace to gasify further. Hence, the unburned carbon losses is negligible.

- In fluidized beds, some unburned carbon escapes with the bed discharge at the bottom. Furthermore, because of lower combustion temperatures in the bed, the carbon content in the flyash is higher. Consequently the unburned carbon loss is relatively higher.

Reduction of NO_x, SO_2 and Particulate Emissions

All of the competitive technologies address NO_x control to various degrees and at various costs. The cause of high NO_x is a combination of fuel-bound nitrogen and thermally generated NO_x. Reductions in NO_x can be achieved at the back end (catalytic and noncatalytic reduction technology) or within the burner or boiler via control of the combustion temperatures and gas compositions. In general, burner or boiler modifications that reduce NO_x formation during the combustion process are the most cost effective means of limiting NO_x emissions.

- TRW combustion system, low NO_x pulverized coal burners, reburn technology, and fluidized beds can significantly reduce NO_x formation within the combustion zone. TRW combustion systems and fluidized beds achieve the lowest levels of NO_x (0.2 lb/MMBTU).

- Selective catalytic reduction (SCR) can achieve high reductions in NO_x levels but are, in general, costly due to high initial capital costs and high operating and maintenance (O&M) costs. Selective noncatalytic reduction (i.e., ammonia or urea) is less costly than SCR. However, ammonia or urea carry-over in the stack gases is of great concern, and hence this system is avoided in many localities.

The causes of high SO_2 emissions are high sulfur levels in the coal and lack of, or insufficient SO_2 capture.

- The TRW technology can achieve 50 to 70% SO_2 removal without any flue gas desulfurization simply by installing a limestone feed system to inject limestone into the exit of the TRW combustor. The SO_2 can be reduced by 90 to 95% by the addition of a spray-dryer scrubber to the TRW system which utilizes the calcined limestone from the TRW combustor. The use of the combustor and boiler for calcination greatly reduces sorbent costs.

- For back-end SO_2 clean up, the options are wet versus dry scrubbers. In general, wet scrubbers are more expensive, both in initial capital costs and O&M costs, primarily because of the need to dispose of wet waste sludge.

- In fluidized beds, SO_2 control is achieved by the use of limestone or dolomite in the bed material. SO_2 removal efficiencies are typically 90 to 95%.

Particulate emissions are typically controlled by back-end particulate removal systems using venturi scrubbers, baghouses or electrostatic precipitators. For dry ash, or dry bottom furnaces, typically 80 to 90% of the ash is removed form the boiler and precipitator hopper in the form of fine dust. For wet bottom furnaces, cyclone furnaces or those equipped with TRW technology, the majority of the coal ash is removed in a molten form.

- In the case of the TRW technology, greater than 80% of the coal ash is removed as molten slag prior to entering the furnace. The molten slag is environmentally neutral and can be utilized as a construction material. The airborne fly ash, typically less than 10 microns in size is removed as solid material in a baghouse.

- In fluidized bed combustors, ash is removed as a dry flyash from primarily two locations: the bed and the baghouse. Typically, only 20% of the particulate is removed from the bed itself and the remainder is carried over into the boiler and ultimately removed from the baghouse. The bed ash is removed to an ash cooler which reclaims heat from solids for use in the cycle. Disposal of the flyash from the bed and baghouse can be difficult.

Impact on Tube Erosion and Fouling

As mentioned previously, erosion and fouling of the furnace, convective pass and superheater tubes are exacerbated by high ash in the coal. Erosion is aggravated by abrasive ash, usually due to higher silica content.

- For the TRW combustion system retrofit, less than 20% of the coal ash enters the boiler. The fines which do enter the furnace are typically less than 10 microns in size and are fused and spherical in shape with smooth surfaces. This results in lower abrasion and, therefore, less erosion, than would occur from conventional flyash.

- Both bubbling and circulating fluidized beds experience in-furnace tube metal loss. The degree of erosion relates to the properties of the coal being fired. This problem may limit the fuel flexibility with regard to specific coal properties or result in decreased availability and increased maintenance costs.

Fuel Flexibility

- The TRW combustion system can burn a variety of coals over a wide range of properties by changing its operating temperatures and stoichiometries. Currently the HCCP is directed toward a low grade coal (low calorific value, high volatiles and high moisture) having a high ash fusion temperature. At the other extreme, the TRW system can even be designed to burn high calorific value, low volatiles anthracitic coals with minimum or no oil-assist. Since the TRW system exploits slagging of ash, utilization of coals with low ash fusion temperatures is accommodated easily.

- Fluidized bed combustors are capable of efficiently burning many of the low grade coals due to the long residence times available in the bed; fluidized beds cannot easily handle coals which agglomerate or have very low ash fusion temperatures. In addition, certain coal properties may contribute to in-bed tube erosion which may limit fuel flexibility.

- In general, low NO_x pulverized coal burner are not capable of efficiently burning low grade coal and require a gas or oil assist.

Power Requirement

The TRW system requires a slightly higher combustion air pressure of typically 40 inches of water (gauge) (1.1 atm). Additional power is also needed to drive the mill exhauster fan and the cooling water circulation pumps. Although the fluidized bed is less demanding in the area of coal preparation (can burn 0" x 1/8" coal), this reduction in auxiliary power is more than offset by the need for "high pressure" combustion air to fluidize the bed. Fan discharge pressures of 70 to 90 inches of water (gauge) (1.17 to 1.22 atm) are typical. If the fluidized bed boiler is equipped with gas-to-air heat recovery, then a change in air heater construction may also be required.

Recovery of Heat in Flyash and Slag

In a standard pulverized coal fired system the heat in the flyash and the gases is recovered in various heat absorption zones in the furnace and back plates until its temperature drops to about 150^0F to 175^0C. This is the same in the low NO_x burners. In the TRW system, however, the slag drops to the quench tank and the sensible heat in the slag is lost. This heat loss is higher for higher slag removal efficiency and higher ash contents. The same magnitude of heat loss is also experienced in wet bottom furnaces and cyclone combustors. In fluidized beds, the spent bed material is discharged at temperatures typically 875^0C to 1100^0C. Depending on site-specific requirements, the sensible heat in this bed material is sometimes recovered by an ash cooler, if the capital cost of this additional equipment is justifiable. This heat loss can be offset by 1 to 2% higher coal input, and for low grade coals this is economically justifiable.

Among all the technologies cited in Figure 9, TRW technology and fluidized beds have a significant performance edge over other technologies. Fluidized beds, however, are not suitable for retrofits. In certain applications TRW technology offers viable advantages over fluidized beds. In certain other applications, fluidized beds will be more attractive. In the final analysis the performance-to-cost ratio will eventually determine the selection for specific applications.

5. ECONOMIC EDGE

Figure 10 presents a comparison of incremental capital and operating costs in 1992 dollars of selected competitive technologies with respect to a conventional pulverized coal-fired power plant as a benchmark without low-NO_x burners or back-end NO_x scrubbing systems.

It is seen that the TRW-Joy combination is competitive with other systems, and in addition, offers significant operating and performance advantages cited in Figure 10.

Incremental Costs (Average Values With ± 20% Margin)		TRW System With Joy-Niro Back End System	Low-NO_x Burners With Conventional Back End Flue-Gas-Desulfurization	Fluidized Bed System
Capital ($/KW)		+ 448	+ 465	+ 513
O&M Cost Related to Back End	Sorbent ($/ton SO_2 Removal)	+98*	+ 325§	+ 350†
O&M Cost Related to Boiler Island	Higher Pressure Combustion air (kW/kW)	+ 0.009 (ΔP = 40" w.g.)	0	+ 0.029 (ΔP = 80" w.g.)
	Mill Exhauster (kW/kW)	+ 0.006 (ΔP= 45" w.g.)	0	0
	Cooling Water Pump (kW/kW)	+ 0.006	0	0
	Pulverizer (kW/kW)	0	0	- 0.0134

* *Limestone-based, Ca/S = 1.1, 90% SO_2 removal*

§ *Lime-based, Ca/S = 1.1, 90% SO_2 removal*

† *Lime-based, Ca/S = 3, 90% SO_2 removal*

Figure 10. Incremental Cost and Power Comparison

6. CONCLUSIONS

The Healy Clean Coal Project, initiated in 1991, as part of the U.S. Department of Energy's Clean Coal Technology Program's Round III competition is the first utility-size demonstration of this technology. The design was completed in 1993 as part of Phase 1. Fabrication activities are currently underway as part of Phase 2. Operation, Phase 3, is scheduled to begin in January 1998. The successful completion of the Healy Clean Coal Project will pave the way for rapid commercialization of this technology worldwide.

TRW is offering licensing of this technology world-wide, except in the People's Republic of China, where TRW already has a licensing agreement.

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AN UPDATE ON LIQUID PHASE METHANOL (LPMEOH™) TECHNOLOGY AND THE KINGSPORT DEMONSTRATION PROJECT

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ABSTRACT

The Liquid Phase Methanol (LPMEOH™) process uses a slurry reactor to convert synthesis gas (primarily a mixture of hydrogen and carbon monoxide) to methanol. The process is designed to handle the carbon monoxide (CO) - rich gas characteristic of gasified coal, petroleum coke, residual oil, wastes, and other hydrocarbon feedstocks. In the Integrated Gasification Combined-Cycle (IGCC) power generation application, CO-rich gas is partially converted to methanol, and the unconverted gas is used to fuel the gas turbine combined-cycle power plant. The LPMEOH™ process has the flexibility to operate in a daily load-following manner, following the demand for electric power output. Co-production of power and methanol via IGCC and the LPMEOH™ process provides opportunities for energy storage for electrical demand peak shaving, clean fuel for export, and/or chemical methanol sales.

The LPMEOH™ technology was developed during the 1980's, and the concept was proven in 7,500 hours of test operation in a 10 ton-per-day process development unit located at LaPorte, Texas. The LPMEOH™ process was selected for demonstration under Round III of the Clean Coal Technology Program. The demonstration project is advancing at Eastman Chemical Company's coal gasification facility in Kingsport, Tennessee. The demonstration unit will produce 260 tons-per-day of methanol and simulate operation in the IGCC application. Start-up is expected to begin in December 1996.

This paper gives a review of the LPMEOH™ technology and highlights the demonstration project at Kingsport. Some LPMEOH™ commercial concepts are also described.

INTRODUCTION

The LPMEOH™ process uses a slurry reactor to convert synthesis gas into methanol. The process is designed to handle the CO-rich (typically 40-65 vol %) feed gas characteristic of gasified coal, petroleum coke, residual oil, wastes, and other hydrocarbon feedstocks. The LPMEOH™ technology is especially synergistic with IGCC electric power. In this application, CO-rich synthesis gas is partially converted to methanol, and the unconverted gas is used to fuel the gas turbine combined-cycle power plant. The LPMEOH™ process has the flexibility to operate in a daily load-following manner, following the demand for electric power output. Co-production of power and methanol provides opportunities for energy storage for electrical demand peak shaving, clean fuel for export, and/or chemical methanol sales.

This paper gives an update on the status of demonstration of the LPMEOH™ process, and reports on the Clean Coal Technology project in Kingsport, Tennessee. Some commercial concepts are also reviewed.

TECHNOLOGY DESCRIPTION

The heart of the LPMEOH™ process is the slurry reactor (Figure 1). The liquid medium is the

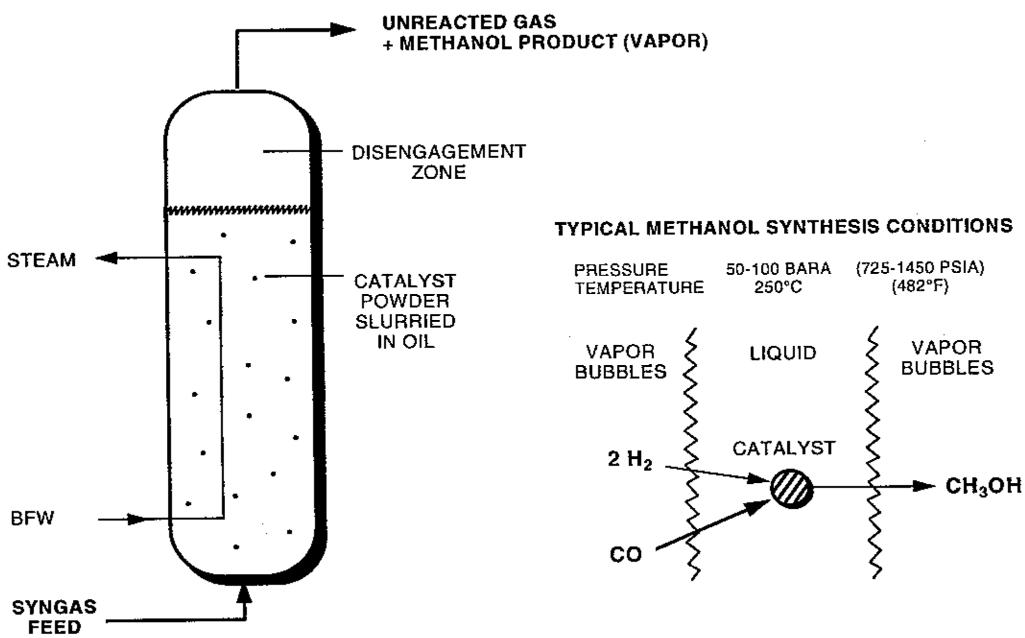

Figure 1. LPMEOH™ Reactor and Reaction Schematics

feature that differentiates the LPMEOH™ process from conventional technology. Conventional methanol reactors use fixed beds of catalyst pellets and operate in the gas phase. The LPMEOH™ reactor uses catalyst in powder form, slurried in an inert mineral oil. The mineral oil acts as a heat sink to absorb the heat of reaction and maintain a constant, highly uniform temperature.

This temperature management in turn facilitates the maintenance of favorable equilibrium conversion conditions. Moreover, the constant temperature and the nature of the liquid protect the catalyst and allow the processing of CO-rich gas, which would normally have strong potential for catalyst damage and deactivation. The ability of the LPMEOH™ process to directly accommodate desulfurized CO-rich synthesis gas from gasification eliminates the traditional need for stoichiometry adjustment by shift (to increase the hydrogen content) and carbon dioxide (CO_2) removal (to reduce the excess carbon oxides level).

A second differentiating feature of the LPMEOH™ reactor is its robust character. The slurry reactor is suitable for rapid ramping, idling, and even extreme stop/start actions. The thermal inertia of the liquid medium provides this unique character. The liquid inventory in the reactor acts to buffer sharp transient operations that would not normally be tolerable in a methanol synthesis plant.

In the LPMEOH™ reactor, the net heat of reaction is transferred from the slurry to boiling water in an internal tubular heat exchanger. The heat transfer coefficient on the slurry side of the heat exchanger is large and (combined with the large steam-side coefficient) leads to a heat exchanger that is relatively small and occupies only a small fraction of the cross-sectional area of the reactor. The steam produced is suitable for purification of the methanol product (for upgrading beyond fuel-grade quality) or for use in the IGCC power generation cycle.

Another unique feature of the LPMEOH™ process is the ability to add fresh catalyst on-line. Methanol catalyst deactivates at a slow rate. With the LPMEOH™ reactor, spent catalyst slurry is withdrawn and fresh catalyst slurry is added on a periodic batch basis. This allows continuous, uninterrupted operation and also the maintenance of a high productivity level in the reactor. Furthermore, choice of replacement rate permits optimization of productivity versus catalyst replacement cost.

HISTORICAL REVIEW

The LPMEOH™ technology was conceived by Chem Systems Inc. The initial concept was based on a liquid-ebullated (liquid-fluidized) bed reactor that used large catalyst pellets. In the 1980's, the slurry reactor concept with powdered catalyst evolved. The initial R&D work received essential support from the Electric Power Research Institute (EPRI), which recognized the fit of methanol co-production with IGCC power generation.

In the 1980's, Air Products & Chemicals, Inc., received a contract from the U.S. Department of Energy (DOE) for further development of the LPMEOH™ technology, culminating in a demonstration at a small but representative engineering scale. Air Products performed as the prime contractor and Chem Systems performed as subcontractor in the project. Air Products, EPRI, and Fluor Engineers, Inc. were cost-sharing participants. Laboratory tests were conducted in bench-scale, stirred-autoclave reactors and in a 4.5" diameter lab bubble column reactor. In parallel, a process development unit (PDU) was designed and constructed at Air Products' industrial gas facility in LaPorte, Texas, just east of Houston. The PDU was designed to test a range of simulated coal-gas compositions, using blended streams from product pipelines at the site (H_2, CO, nitrogen, methane, and imported CO_2). The PDU was designed for a nameplate production capacity of 5 tons-per-day of methanol, but eventually ran at more than 10 tons-per-day.

The LaPorte LPMEOH™ reactor diameter was 22.5", with an initial overall height of approximately 20'. The reactor height was later increased to about 30' to incorporate vapor-liquid disengagement. Proof-of-concept testing was successfully concluded with 2,500 hours of operation on synthesis gas. These tests were satisfying but also showed opportunities to improve reactor productivity and to simplify the system. It was further recognized that a longer continuous run was necessary to demonstrate the catalyst life trend on CO-rich gas. With DOE's strong support and EPRI's assistance, Air Products performed follow-up R&D to address these issues and complete the development effort. The LaPorte demonstration ended with 7,460 hours of operation, including a 120-day continuous run. The success of these final phases positioned LPMEOH™ technology for advancement to commercial-scale demonstration. The scope of the LPMEOH™ data base established at LaPorte is summarized in Table 1.

	Range	Typical
Simulated Coal-Gas Compositions:	CO-Rich (Texaco), Shell, Destec, Lurgi, Alt CO-Rich, Balanced, H_2-Rich	CO-Rich
CO Concentration, vol %	19 - 65	51
H_2/CO Ratio	0.49 - 3.9	0.69
CO_2 Concentration, vol %	1 - 16	13
Reactor: Pressure, psia	515 - 915	765
Temperature, °F	440 - 520	482
Space Velocity, liters/hr-kg oxide catalyst	0 - 17,500	10,000
Superficial Inlet Gas Velocity, ft/sec	0 - 0.72*	0.6
Catalyst Slurry Concentration, wt % oxide	15 - 50	40
Methanol Production Rate, short tons/day	0 - 12.8	10
Crude Methanol Product Purity, wt %	93 - 99	97
Ramp Rate, % of full capacity per minute	0 - 16	6
No. of Synthesis Gas Operating Campaigns/Runs:	10	
No. of 6-14 Day Runs	6	
No. of 40-50 Day Runs	3	
No. of 120-Day Runs	1	
No. of Steady-State Performance Conditions	93	
Cumulative Operating Statistics:		
Synthesis Run Time, hours	7,460	
CO-Rich Gas Run Time, hours	6,350	
Methanol Production, short tons	2,290	
On-Stream Factor, %	98	
On-Stream Factor excluding Hurricane Gilbert, %	99	

*1.20 ft/sec achieved post-1989

Table 1. Scope of LPMEOH™ Testing at LaPorte Process Development Unit, 1984-1989

As a point of interest, the LaPorte PDU facility, which is owned by DOE and operated by Air Products, was modified in 1991 for testing analogous liquid phase technologies (i.e., production of isobutanol/mixed alcohols, dimethyl ether, Fischer-Tropsch hydrocarbons, hydrogen via liquid phase shift). The facility was renamed the Alternative Fuels Development Unit (AFDU) and subsequently expanded to include a second, taller slurry reactor with a higher pressure capability. Air Products continues to test advanced liquid phase technologies at LaPorte, under DOE sponsorship in a cost-sharing arrangement. (Some additional LPMEOH™ data has also been generated under this on-going program, primarily for the purpose of baselining new equipment. This data is not included in Table 1.)

Air Products owns the LPMEOH™ technology.

DEMONSTRATION PROJECT

Overview/Objective

The LPMEOH™ process was selected for demonstration under Round III of the Clean Coal Technology Program. The demonstration project will be located at Eastman Chemical Company's coal gasification facility in Kingsport, Tennessee. Construction is beginning this month (September 1995) and is expected to be complete in November 1996. The 4-year demonstration operating period will begin in December 1996.

The objective of the Kingsport project is the commercial-scale demonstration of LPMEOH™ technology using coal-derived synthesis gas. The operating/test program will verify scale-up in a commercial facility setting. The 4-year operating program includes operation on a range of synthesis feed gas compositions and demonstration of stop/start/cycling capability simulating electrical demand load-following operation. The project will also demonstrate the suitability of product fuel-grade methanol in off-site fuel (and potentially chemical feedstock) tests.

The LPMEOH™ demonstration plant will produce up to 260 tons-per-day of methanol from a portion of the available clean synthesis gas. Most of the product methanol will be refined to chemical-grade quality (99.85 wt % purity via distillation) and used by Eastman as replacement feedstock in the commercial facility. A portion of the product methanol will be withdrawn prior to purification (about 97 wt % purity) and used in the off-site fuel-grade methanol use tests.

Organizations and Roles

Air Products and Eastman have formed a 50/50 partnership, "Air Products Liquid Phase Conversion Co., L.P.," to execute the demonstration project. The partnership will own the LPMEOH™ plant. Air Products will manage the demonstration project, design, procure, and construct the LPMEOH™ unit (i.e., a turnkey plant), and provide technology analysis and direction. Eastman will provide the host site and supporting auxiliaries, perform permitting, operate the LPMEOH™ unit, supply synthesis gas, and take product methanol.

Other private participants are Acurex Environmental Corporation, which will perform as a subcontractor to Air Products and manage the off-site fuel use tests, and EPRI, which will provide analysis and guidance from the utility sector.

Schedule and Current Status

Figure 2 gives the project schedule for the engineering, procurement, and construction portion of the demonstration project. As of this month (September 1995), Process Engineering is

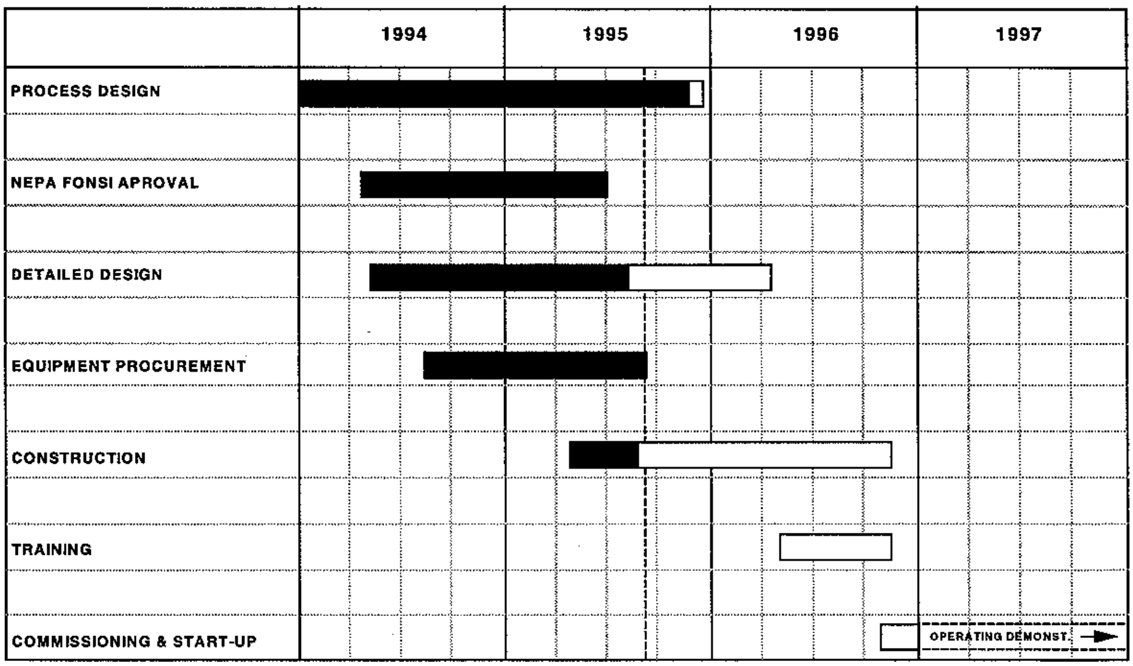

Figure 2. Schedule for Engineering, Procurement, and Construction of LPMEOH™ Unit

essentially complete, and Detailed Plant Design Engineering is 45 % complete. All equipment has been specified and purchased except for two vent drums. Equipment deliveries begin in November 1995. The State air permit was received in March of this year. The DOE has completed its National Environmental Policy Act (NEPA) review and issued a Finding of No Significant Impact (FONSI). Civil construction at the site begins this month. It is anticipated construction will be complete and commissioning underway in the fourth quarter of 1996. Startup and test operation is expected to begin in December 1996.

The operating test program will end in early January 2001, concluding the 4-year test period. The off-site fuel use tests will be performed over a 20-month period, beginning in January 1998 and ending in August 1999.

Kingsport Site

Kingsport is located in the northeast corner of Tennessee, just below the Virginia border and 35 miles northwest of North Carolina. Eastman began coal gasification operations at Kingsport in 1983. The site (Figure 3) is located along the South Fork Holston River. Texaco gasification is

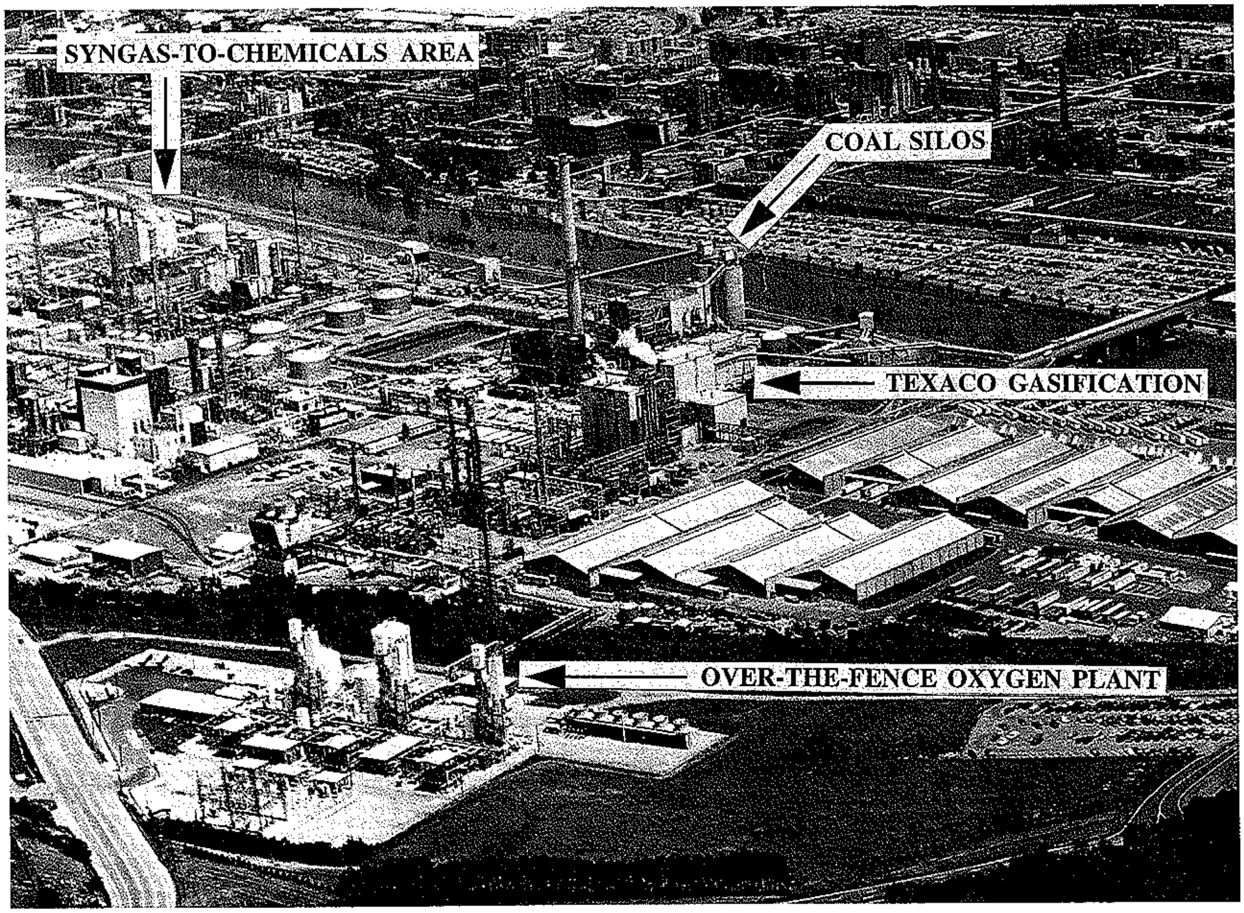

Figure 3. Overhead View of Eastman's Kingsport Complex

used to convert about 1,000 tons-per-day of high-sulfur, Eastern bituminous coal to synthesis gas for the manufacture of methanol, acetic anhydride, and associated products. Air Products provides the oxygen for gasification by a pipeline from an over-the-fence air separation unit. The crude synthesis gas is quenched, partially shifted, treated for acid gas removal (hydrogen sulfide and carbonyl sulfide, and CO_2, via Rectisol), and partially processed in a cryogenic separation unit to produce separate H_2 and CO streams. The H_2 stream is combined with clean synthesis gas to produce stoichiometrically balanced feed to a conventional gas phase methanol synthesis unit. Methanol from this unit is reacted with recovered acetic acid to produce methyl acetate. Finally, the methyl acetate is reacted with the CO stream to produce the prime product, acetic anhydride (and acetic acid for recycle).

The LPMEOH™ demonstration unit will be located northwest of the gasification area (Figures 4 and 5), near the existing, conventional gas phase methanol plant.

Process Block Flow Diagram for LPMEOH™ Demonstration

The LPMEOH™ demonstration unit will produce up to 260 tons-per-day of methanol, using a portion of the available clean synthesis gas. Because the gasification facility produces individual

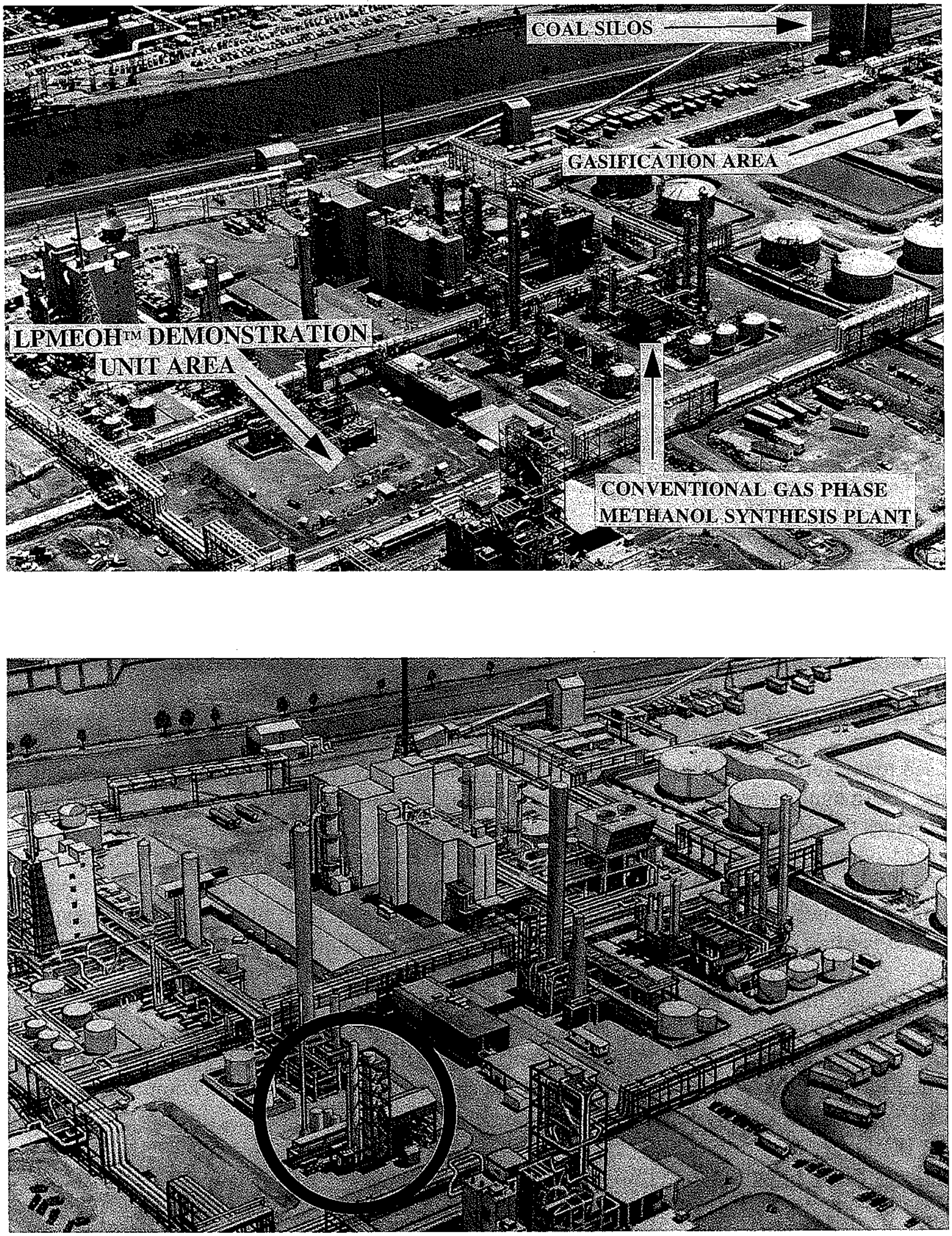

Figure 5. Illustration of Site with Installed LPMEOH™ Demonstration Unit

streams of clean synthesis gas, CO, and H_2-rich gas, there is the capability to blend gases and mimic the clean coal gas compositions of a range of gasifiers. Figure 6 shows the Process Block

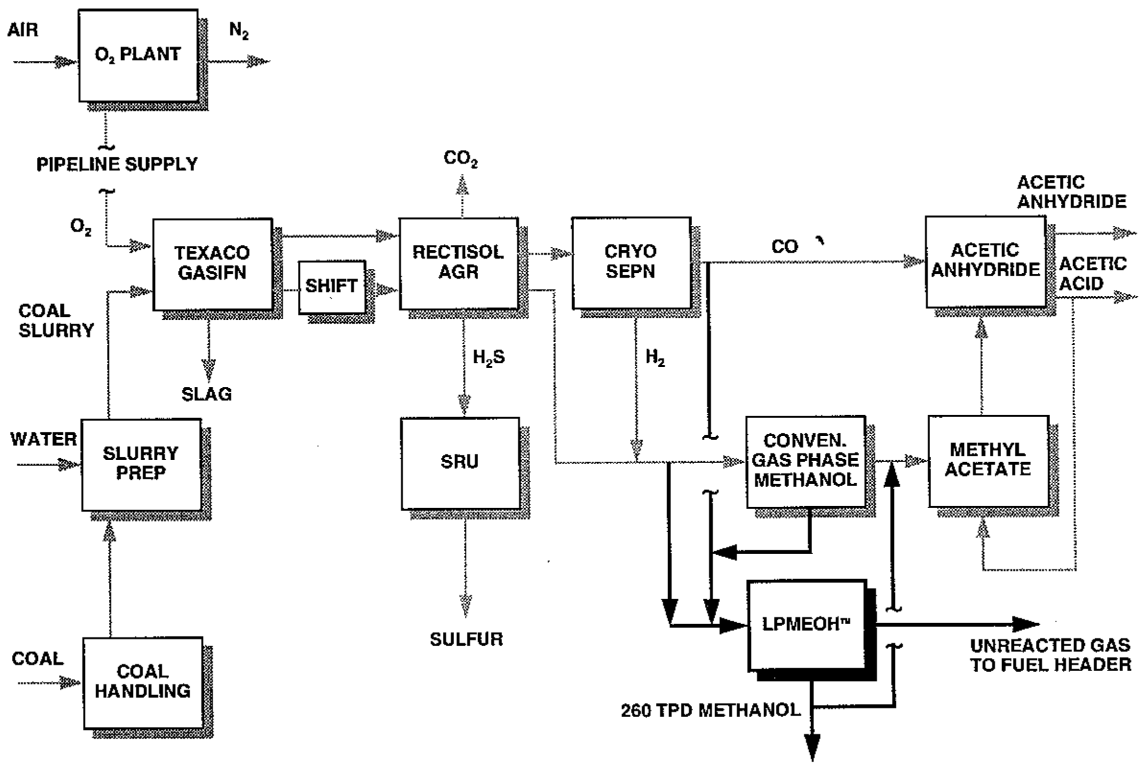

Figure 6. Process Block Flow Diagram of Kingsport Facility Including LPMEOH™ Demonstration Unit

Flow Diagram for the Kingsport facility including the LPMEOH™ demonstration unit.

Demonstration Test Plan

The LPMEOH™ operating test outline, by year, is given in Table 2.

The test plan encompasses the range of conditions and operating circumstances anticipated for methanol co-production with electric power in an IGCC power plant. Since Kingsport does not have a combined-cycle power generation unit, the tests will simulate the IGCC application. Test duration will be emphasized in the test program. The minimum period for a test condition, short of the rapid ramping tests, is 2 weeks. Numerous tests will have 3-6 week run periods, some 8-12 weeks, and a few key baseline tests 20-30 weeks.

The preliminary plans for off-site use testing of fuel-grade (about 97-98 wt % purity) methanol include demonstrations at several sites. The methanol will be tested as a transportation fuel in buses and van pools and as a power generation fuel in fuel cells, gas turbines, and/or other small-use point generators (the final off-site plan is still under development and will be presented in a future paper).

Year 1	Catalyst Aging	
	Catalyst Life Versus LaPorte PDU and Lab Autoclaves	
	Process Optimization	
	Catalyst Slurry Concentration	
	Catalyst Slurry Addition Frequency Test	
	Establishment of Baseline Condition	
Years 2 & 3	Catalyst Slurry Addition and Withdrawal at Baseline Condition	
	Synthesis Gas Composition Studies for Commercial Gasifiers	
	Simulation of IGCC Co-Production via Once-Through Methanol:	
	Texaco, Shell, Destec, British Gas/Lurgi, Other	
	Load-Following	
	Simulation of Electrical Demand Load Following in IGCC Flowsheet:	
	Turndown, Rapid Ramping, Hot and Cold Standby	
	Maximum Catalyst Slurry Concentration	
	Maximum Throughput/Production Rate	
Year 4	Extended Operation at Optimum Conditions	
	99 % Availability	
	Potential Alternative Catalyst Test	
	Additional User Tests	

Table 2. LPMEOH™ Demonstration Test Outline

COMMERCIAL CONCEPTS

Design/Flowsheet Configurations

The LPMEOH™ process can be deployed with IGCC in a number of ways. The process can be be operated in a continuous, baseload manner, converting excess synthesis gas from oversized gasifiers or from a spare gasifier. It can also be operated only during off-peak power periods to consume up to one-half of the synthesis gas and allow the power output from the combined-cycle unit to be turned down. In this latter circumstance, the gasifiers continue to operate at full baseload capacity, so the major portions of the IGCC facility assets are fully utilized. In either baseload or cycling operation, partial conversion of between 20 and 50% (of the flowing Btu energy in the feed gas) is feasible.

The design configuration for the LPMEOH™ process depends upon the amount of conversion of synthesis gas (or the quantity of methanol) required and the feed gas pressure. Reaction pressure for methanol synthesis is usually 750 psia or higher (Figure 7). Depending on the gasification pressure and the required conversion, either once-through-methanol (OTM) synthesis or synthesis with recycle can be used. Once-through methanol synthesis is ideal for facilities requiring moderate conversion (e.g., up to 25 %).

When the required conversion is high (e.g., 50 %), "simple recycle" is used. With the LPMEOH™ process, simple recycle refers to recycle of CO-rich gas; there is still no upstream

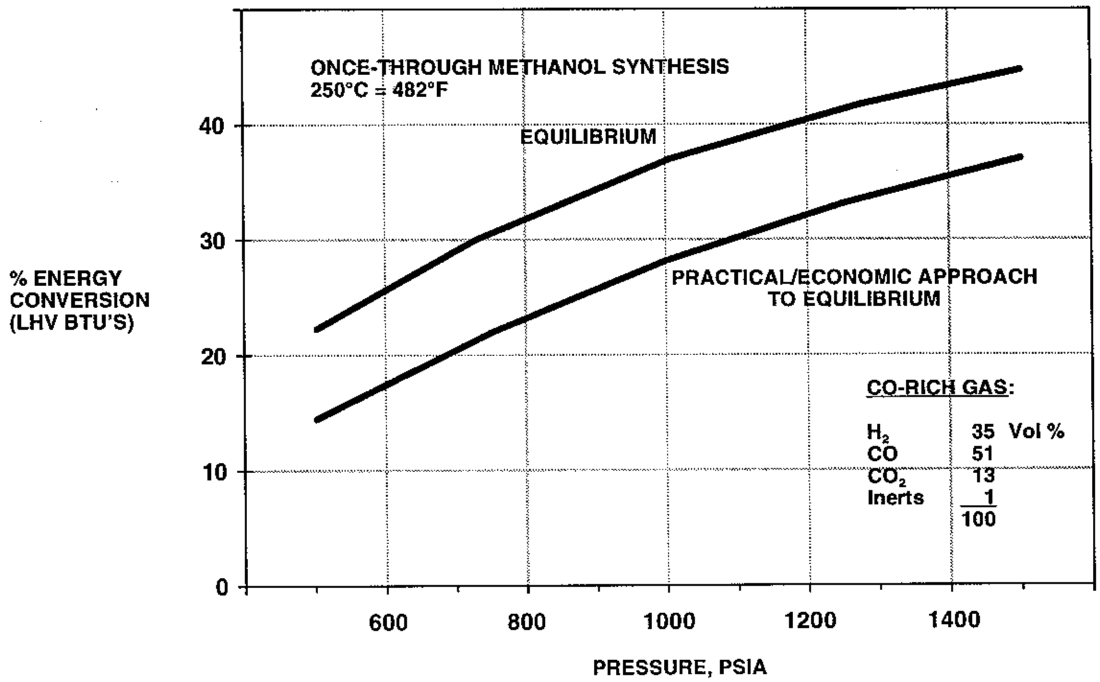

Figure 7. Synthesis Gas Conversion to Methanol

adjustment of the feed gas stoichiometry by shift and CO_2 removal. The required LPMEOH™ recycle ratio is usually moderate, for example, one part unreacted syngas to one part fresh feed gas.

When the feed synthesis gas pressure is low, feed gas compression is added to the LPMEOH™ design. However, even with feed gas compression and recycle, there is still no upstream shift or CO_2 removal, so the simplicity of CO-rich gas processing is retained.

The LPMEOH™ OTM co-production configuration is compared schematically to the conventional gas phase methanol route in the IGCC electric power application in Figure 8.

Product Methanol Quality

The product methanol from an IGCC co-production facility can be used in a number of ways. The use determines the degree of purification required within the LPMEOH™ plant. For fuel use, the crude methanol derived from CO-rich gas need only be stabilized (light gases flashed off). The resultant "fuel-grade" methanol product is about 97-98 wt % purity methanol. The main impurities are higher alcohols and ethers (less than 2 %) and water (less than 1 %). For use as feedstock for MTBE production, the crude methanol product in principle need only be distilled in a single stabilizer/distillation column to further remove light gases. The resultant "MTBE-grade" methanol product is still about 97-98 wt % purity methanol. For use as feedstock for general chemicals production, the crude methanol is purified in a two-column arrangement, with

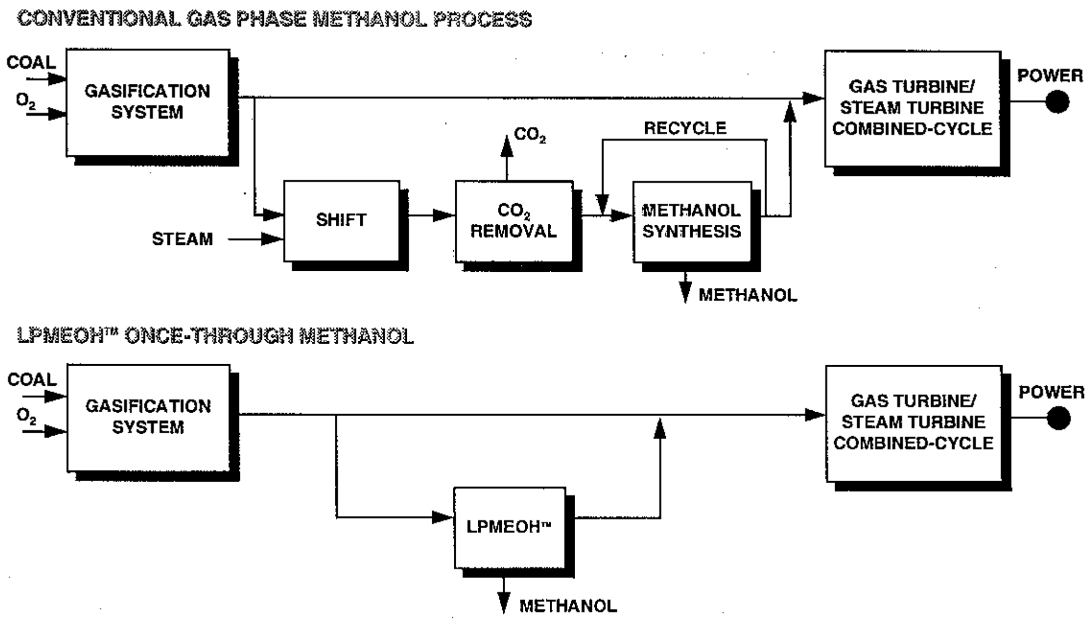

Figure 8. Flowsheet Options for Co-Production of Methanol and Power

the stabilizer/distillation column followed by a refining column that removes heavy alcohols and water. The resultant "chemical-grade" methanol is 99.85 wt % purity methanol. Obviously, fuel-grade methanol production has the lowest capital cost and requires the minimum amount of steam for purification. The remainder of this section deals with fuel-grade methanol production.

Fuel-grade methanol co-produced in an IGCC facility can be used as: 1.) backup fuel for the main gas turbine combined-cycle; 2.) fuel for a separate, dedicated cycling combined-cycle unit at the same site (the "Dispatchable Energy Storage" concept described below); or 3.) fuel exported to distributed power generation systems (e.g., small gas turbines, internal combustion engines, fuel cells).

IGCC Co-Production for Dispatchable Energy Storage

Figure 9 shows the schematic for an IGCC Dispatchable Energy Storage (DES) facility equipped with LPMEOH™ co-production and linked with other new or existing gas turbine generators to provide intermediate and/or peaking power from methanol. In this example, the base IGCC plant consists of a single gasifier and twin turbine train (CC #1 and CC #2), and the two additional turbines (CC #3 and CC #4) are equal-sized, combined-cycle modules. This facility can dispatch between 125 and 500 MW. Many other combinations of generation capability are possible using the DES concept. The key common point is that methanol energy storage can provide a cost-effective means to produce minimal off-peak power to the grid, while shifting generation capability to provide dispatchable intermediate or peaking output.

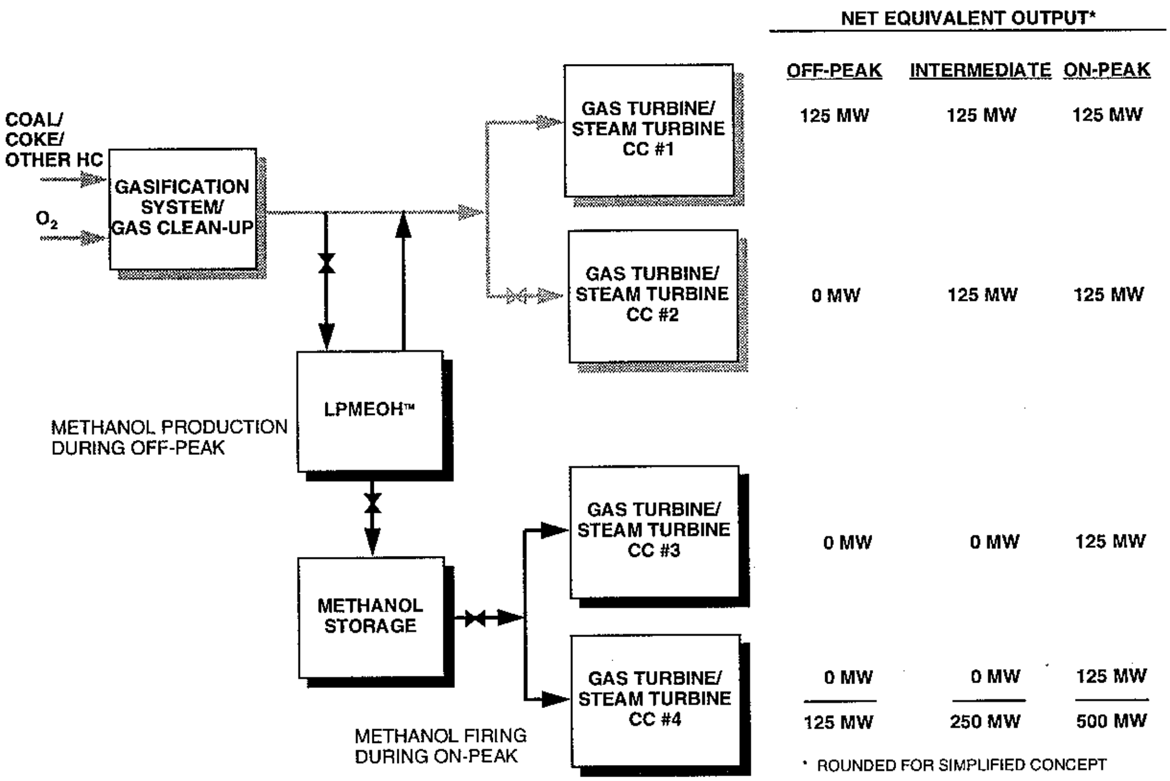

Figure 9. Conceptual IGCC Facility With LPMEOH™ Co-Production for Dispatch Flexibility

Figure 10 illustrates the weekday hourly capability of the IGCC/DES facility depicted in Figure 9. Some weekly average performance data is also given. Methanol is produced 12 hours each day, seven days a week. When methanol is being produced, CC #2 is shut down. On weekends, the facility output cycles between 125 and 250 MW. On weekdays, CC #1 and CC #2 follow the same loading pattern as on weekends, but in addition, for seven hours each day, units CC #3 and CC #4 are brought into service burning methanol. With all units operating, net power to the grid is 500 MW. The total weekly generation is 40.3 GWH, with nearly 60% of this generation dispatched during the high-load weekday hours. The average weekday peak/off-peak (12 hours on/12 hours off) generation ratio is 3.2 MWH/MWH. The average weekly heat rate from coal is about 9000 HHV Btu/kwh. The DES peaking ratio can be increased further by maintaining methanol production throughout the weekend (to 24 hours/day) and storing more fuel for weekday consumption. The dispatch profile can also be varied by changing the individual firing times of CC #3 and CC #4; for example, one alternative (shown on Figure 10) would be to fire CC #3 alone for 4 hours and both CC #3 and CC #4 for 5 hours.

The DES facility can be linked to new, dedicated combined-cycle intermediate load units as depicted in Figure 9, or to existing combined-cycle or simple cycle peaking units converted for methanol consumption. These units may be at the same site, or remotely located with methanol transported to and stored at these distributed sites. In either case, the transportability, storability and clean-burning characteristics of methanol make a methanol-based IGCC/DES plant a

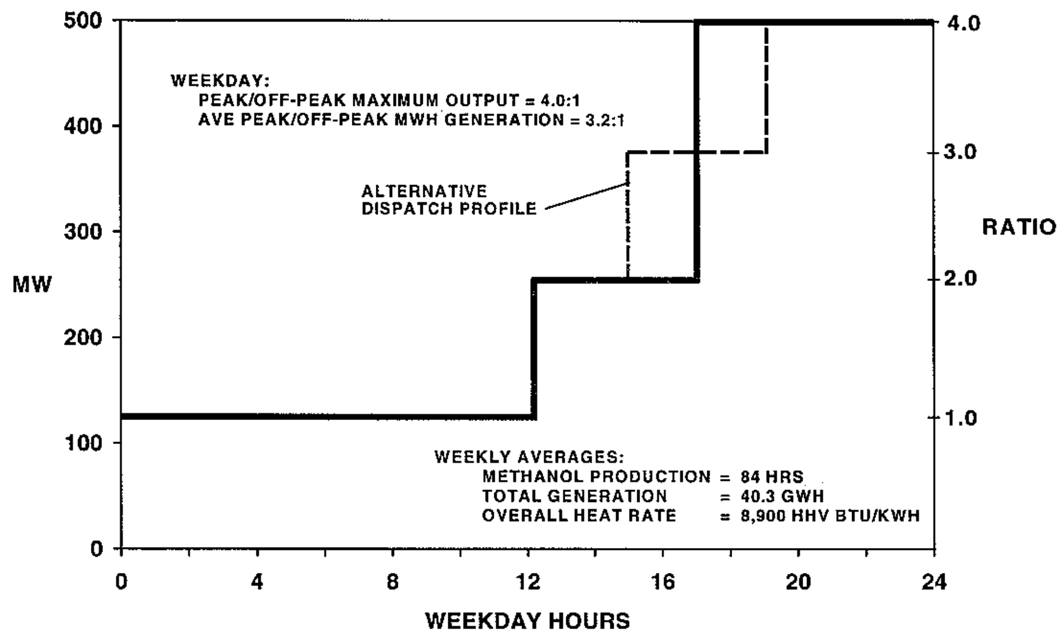

Figure 10. Weekday Generation Capability With IGCC Dispatchable Energy Storage

valuable, flexible asset in a utility system. The LPMEOH™ co-production capability adds only about 10% to the cost of a baseload IGCC facility and provides extraordinary flexibility to effectively dispatch energy from the coal pile.

The LPMEOH™ process can thus expand the applicability of IGCC to satisfy dispatch as well as baseload needs of power producers, while retaining IGCC's high efficiency, low feedstock cost, and environmental advantages. In the example just described, the main IGCC facility retains it's full baseload capability and heat rate when operating in the "all power" mode.

Since methanol is an ultra-clean fuel with zero sulfur and burns with very low NO_x emissions (better than natural gas), the incremental peak power is very clean. Since the peak fuel is derived from the coal pile, the facility can be truly independent and self-sufficient for fuel needs. Finally, should the external prices for methanol command higher value to the plant owner, the methanol can be exported for additional revenues.

CONCLUSION

The LPMEOH™ process is now advancing toward commercial-scale demonstration under the Clean Coal Technology Program. The demonstration unit at Eastman Chemical Company's Kingsport, Tennessee coal gasification facility will produce 260 tons-per-day of methanol from coal-derived synthesis gas. Start-up is expected in December 1996.

LPMEOH™ technology will add significant flexibility and dispatch benefits to IGCC, which has traditionally been viewed as strictly a baseload power generation technology.

Session II

Advanced SO_2/NO_x Emission Reduction Technologies

500 MW DEMONSTRATION OF ADVANCED WALL-FIRED COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN OXIDE EMISSIONS FROM COAL-FIRED BOILERS

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ABSTRACT

This paper discusses the technical progress of a U. S. Department of Energy Innovative Clean Coal Technology project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NOx) emissions from coal-fired boilers. The primary objective of the demonstration is to determine the long-term NOx reduction performance of advanced overfire air (AOFA), low NOx burners (LNB), and advanced digital control/optimization methodologies applied in a stepwise fashion to a 500 MW boiler. The focus of this paper is to report (1) on the installation of three on-line carbon-in-ash monitors and (2) the design and results to date from the advanced digital control/optimization phase of the project.

INTRODUCTION

This paper discusses the technical progress of one of the U. S. Department of Energy's Innovative Clean Coal Technology (ICCT) projects demonstrating advanced combustion techniques for the reduction of nitrogen oxide (NOx) emissions from wall-fired boilers. The demonstration is being conducted on Georgia Power Company's Plant Hammond Unit 4, a 500 MW, pre-NSPS (New Source Performance Standards), wall-fired boiler. Plant Hammond is located near Rome, Georgia, northwest of Atlanta.

The Hammond project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern Company, the U. S. Department of Energy (DOE), and the Electric Power Research Institute (EPRI). In addition to SCS, Southern includes the five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to the Southern electric system. The ICCT program is a jointly funded effort between DOE and industry to move the most promising advanced coal-based technologies to the commercial marketplace. The goal of ICCT projects is the demonstration of commercially feasible, advanced coal-based technologies that have already reached the "proof-of-concept" stage. The ICCT projects are jointly funded endeavors between the government and the private sector in which the industrial participant contributes at least 50 percent of the total project cost. The DOE is participating through the Office of Clean Coal Technology at the Pittsburgh Energy Technology Center (PETC).

The primary objective of the demonstration is to determine the long-term NOx reduction performance of advanced overfire air (AOFA), low NOx burners (LNB), and advanced digital control/optimization methodologies applied in a stepwise fashion to a 500 MW boiler. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends [1,2,3,4].

Following a brief unit and technology review, this paper focuses on the design and results to date from the advanced digital control/optimization phase of the project.

UNIT AND TECHNOLOGY REVIEW

Georgia Power Company's Plant Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW gross, with design steam conditions of 2500 psig and 1000/1000°F superheat/reheat temperatures, respectively. The unit was placed into commercial operation on December 14, 1970. Prior to the LNB retrofit in 1991, six FWEC Planetary Roller and Table type mills provided pulverized eastern bituminous coal (12,900 Btu/lb, 33% VM, 53% FC, 72% C, 1.7% S, 1.4% N, 10% ash) to 24 pre-NSPS, Intervane burners. The burners are arranged in a matrix of 12 burners (4W x 3H) on opposing walls with each mill supplying coal to four burners per elevation (Figure 1).

During a spring 1991 unit outage, the Intervane burners were replaced with FWEC Controlled Flow/Split Flame (CF/SF) burners. In the CF/SF burner, secondary combustion air is divided between inner and outer flow cylinders. A sliding sleeve damper regulates the total secondary air

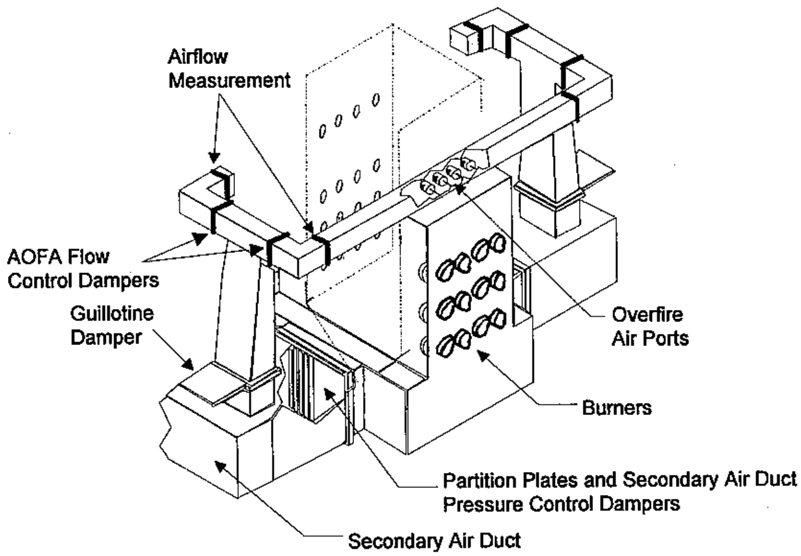

Figure 1. Hammond Unit 4 Furnace Layout

flow entering the burner and is used to balance the burner air flow distribution. An adjustable outer register assembly divides the burner's secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air that traverses the inner path, flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer air flow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace. This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process.

As part of this demonstration project, the unit was also retrofit with an Advanced Overfire Air (AOFA) system. The FWEC design diverts air from the secondary air ductwork and incorporates four flow control dampers at the corners of the overfire air windbox and four overfire air ports on both the front and rear furnace walls. Due to budgetary and physical constraints, FWEC designed an eight port AOFA system more suitable to the project and unit than the twelve port system originally proposed.

The Unit 4 boiler was designed for pressurized furnace operation but was converted to balanced draft operation in 1977. The unit is equipped with a coldside ESP and utilizes two regenerative secondary air preheaters and two regenerative primary air heaters. During the course of the ICCT demonstration, the unit was retrofitted with six Babcock & Wilcox MPS 75 mills (two each during the spring 1991, spring 1992, and fall 1993 outages).

REVIEW OF PRIOR TESTING

Baseline, AOFA, LNB, and LNB+AOFA test phases have been completed (Table 1). Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NOx burners were then installed during a seven week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing was commenced during July 1991 and continued until January 1992. Testing in the LNB+AOFA configuration was completed during August 1993. During both the LNB and LNB+AOFA, there were significant increases (when compared to baseline) in precipitator fly ash loading and gas flow rate and also, increases in fly ash LOI which adversely impacted stack particulate emissions and forced the unit to be load limited [5].

Table 1. Project Schedule

Phase	Description	Date	Status
0	Pre-Award Negotiations		
1	Baseline Characterization	8/89 - 4/90	*Completed*
2	Advanced Overfire Air Retrofit (AOFA) & Characterization	4/90 - 3/91	*Completed*
3A	Low NOx Burner Retrofit (LNB) & Characterization	3/91 - 1/92	*Completed*
3B	LNB+AOFA Characterization	1/92 - 8/93	*Completed*
4	Digital Controls/Optimization Retrofit & Characterization	9/93 - 9/95	In Progress
5	Final Reporting and Disposition	9/95 - 12/95	Later

A summary of the baseline, AOFA, LNB, and LNB+AOFA long-term NOx emissions data for Hammond Unit 4 is shown in Figure 2. Baseline testing was performed in an "as-found" condition. For the AOFA, LNB, and LNB+AOFA test phases, following optimization of the unit by FWEC personnel, the unit was operated according to FWEC instructions provided in the design manuals. As shown, the AOFA, LNBs, and LNB+AOFA provide a long-term, *full load*, NOx reduction of 24, 48, and 68 percent, respectively. The *load-weighted* average of NOx emissions reductions was 14, 48, and 63 percent, respectively, for AOFA, LNBs, and LNB+AOFA test phases. Although the LNB plus AOFA NOx level represents a 67 percent reduction from baseline levels, a substantial portion of the incremental change in NOx emissions between the LNB and LNB+AOFA configurations is the result of operational changes and is not the result of the AOFA system [6].

The *time-weighted* average of NOx emissions for the baseline, AOFA, LNB, LNB+AOFA test phases are shown in Table 2. Since NOx emissions are generally dependent on unit load, the NOx values shown in this table are influenced by the load dispatch of the unit during the corresponding test frame. Also shown in this table are the 30 day and annual achievable emission limits as determined during these test periods. The 30-day rolling average achievable emission limit is defined as the value that will be exceeded, on average, no more than one time per ten years. For the annual average, a compliance level of 95 percent was used in the calculation.

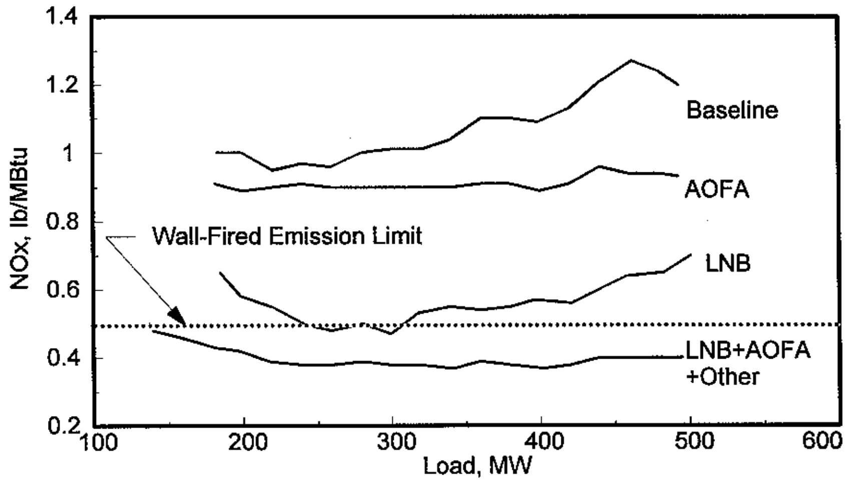

Figure 2. Long-Term NOx Emissions vs. Load Characteristic

Table 2. Long-Term NOx Emissions

Unit Configuration →	Baseline		AOFA		LNB		LNB+AOFA	
Parameter ↓	Mean	RSD,%	Mean	RSD,%	Mean	RSD,%	Mean	RSD,%
Number of Daily Avg. Values	52	-	86	-	94	-	63	-
Load (MW)	407	9.4	386	17.9	305	17.7	293	23.9
NOx Emissions (lb/MBtu)	1.12	9.5	0.92	8.6	0.53	13.7	0.41	12.9
O2 Level (percent at stack)	5.8	11.7	7.3	12.6	8.4	7.7	8.73	16.3
NOx 30 Day AEL (lb/MBtu)	1.24	-	1.03	-	0.64	-	0.51	-
NOx Annual AEL (lb MBtu)	1.13	-	0.93	-	0.55	-	0.42	-

EVALUATION OF ON-LINE CARBON-IN-ASH ANALYZERS

A subsidiary goal of the Wall-Fired project is the evaluation of advanced instrumentation as applied to combustion control. Based on this goal, several on-line carbon-in-ash monitors are being evaluated as to their:

- Reliability and maintenance,
- Accuracy and repeatability, and
- Suitability for use in the control strategies being demonstrated at Hammond Unit 4.

Three units are currently installed at this site: (1) Applied Synergistics FOCUS, (2) CAMRAC Corporation CAM, and (3) Clyde-Sturdevant SEKAM. The SEKAM unit samples from two locations at the economizer outlet while the CAM unit samples from a single location at the precipitator inlet (Figure 3). The FOCUS unit is a non-extractive system that utilizes two cameras located above the nose of the furnace. The following paragraphs briefly describe these devices.

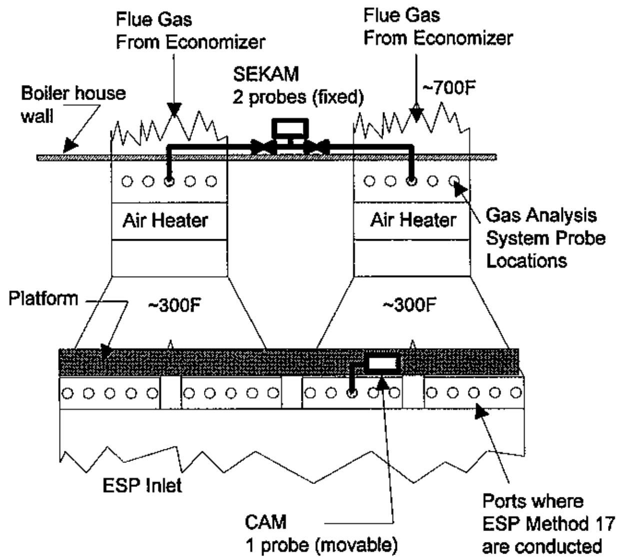

Figure 3. Sample Locations of CAM and SEKAM Carbon-in-Ash Analyzers

Clyde-Sturdevant SEKAM

The SEKAM™ unit was developed by the UK Central Electric Generating Board (CEGB). As a result of the dissolution of the CEGB, ownership of the SEKAM technology was eventually transferred to Clyde-Sturdevant Engineering. A sketch of the SEKAM system is shown in Figure 4. The basis of the SEKAM device is the measurement of capacitance of the fly ash sample using a Kajaani cell which was developed by the Finish firm Kajaani Limited. Ash collected from the flue gas stream (or other locations) is deposited in a glass chamber of rectangular cross section measuring 150x70x20 mm (5.91x2.76x0.79 inches) placed between two capacitance sensors. The cell, flyash, and sensors are integrated into a circuit such that the output

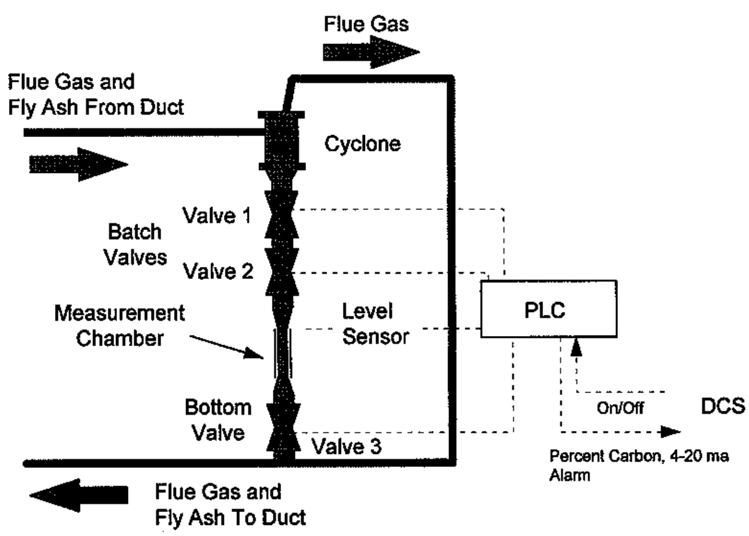

Figure 4. SEKAM General Arrangement

voltage of the circuit is a function of the measured capacitance. The device presumes a fixed relationship between the measured capacitance and carbon-in-ash. The installation at Hammond Unit 4 can sample from either the "A" or "B" side economizer outlet gas stream or from both probes simultaneously. It is expected that, except for short-term testing, the SEKAM will be configured to extract flue gas from both the "A" and "B" sides simultaneously thus shortening the sampling cycle time and improving the likelihood of obtaining a representative fly ash sample. Since the SEKAM device requires a relatively large fly ash sample (approximately 150 cm3 ~ 375 g), in order to reduce the overall sampling time, the system samples super-isokinetically. An exhauster is used to supply the motive force to transport the flue gas and fly ash. Super-isokinetic sampling can have either a positive or negative impact on overall sampling accuracy.

The SEKAM system was installed on Hammond 4 during December 1994. Testing is now being conducted to verify the accuracy of the SEKAM system.

CAMRAC CAM

CAMRAC Company's CAM (Carbon-Ash-Monitor) unit was developed during the 1980s by GAI Consultants (an affiliate of CAMRAC Company) with financial support from Allegheny Power Services Corporation, Duquesne Light Company, New England Power Services, NYSEG, Southern Company Services, Virginia Power, and EPRI. The CAM system uses the relative microwave absorbence between carbon and carbon-free fly ash to infer the carbon content of the sample. A schematic of a CAM system is shown in Figure 5. The installation at Hammond Unit 4 samples from one of twenty sample ports located at the inlet to the precipitator. The system has been designed such that vertical traverses of the flue gas stream can be conducted.

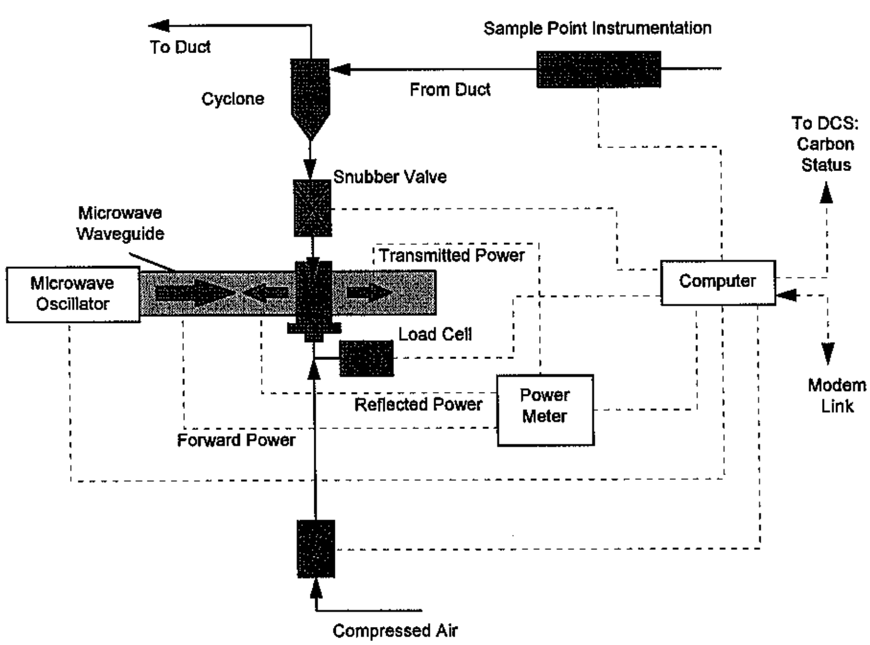

Figure 5. CAMRAC General Arrangement

During long-term testing, fly ash samples will be drawn from a single location. For short-term testing, several sample ports and depths will be used so that a spatial distribution of the unburned carbon can be obtained.

The CAM system was installed on Hammond 4 during February 1995. Testing is now being conducted to verify the accuracy of the CAM system.

Applied Synergistics FOCUS

The Applied Synergistic's FOCUS™ Unburned Carbon Module is a non-intrusive real-time device which provides a timely, continuous on-line indication of unburned carbon in fly ash. The device is based on the premise that unburned carbon particles and carbon laden ash particles exiting the furnace will be hotter than the surrounding background gases, carbon-free ash particles, and support structures, and therefore the carbon-laden particles will be higher emitters of radiant energy, especially in the infrared range. The primary sensing elements are one or more near infrared video cameras installed on the furnace. The hotter particles will be seen as white spots traversing the camera(s) field of view and these images are processed to determine the number of traverses in counts per minute. The assumption is then made that the carbon-in-ash (on a percent basis) is a function of these counts and unit load. Two cameras are utilized at Hammond 4. A sketch of the system is shown in Figure 6.

The FOCUS Unburned Carbon Module was installed during July 1995. Testing of this device for calibration and verification purposes has begun.

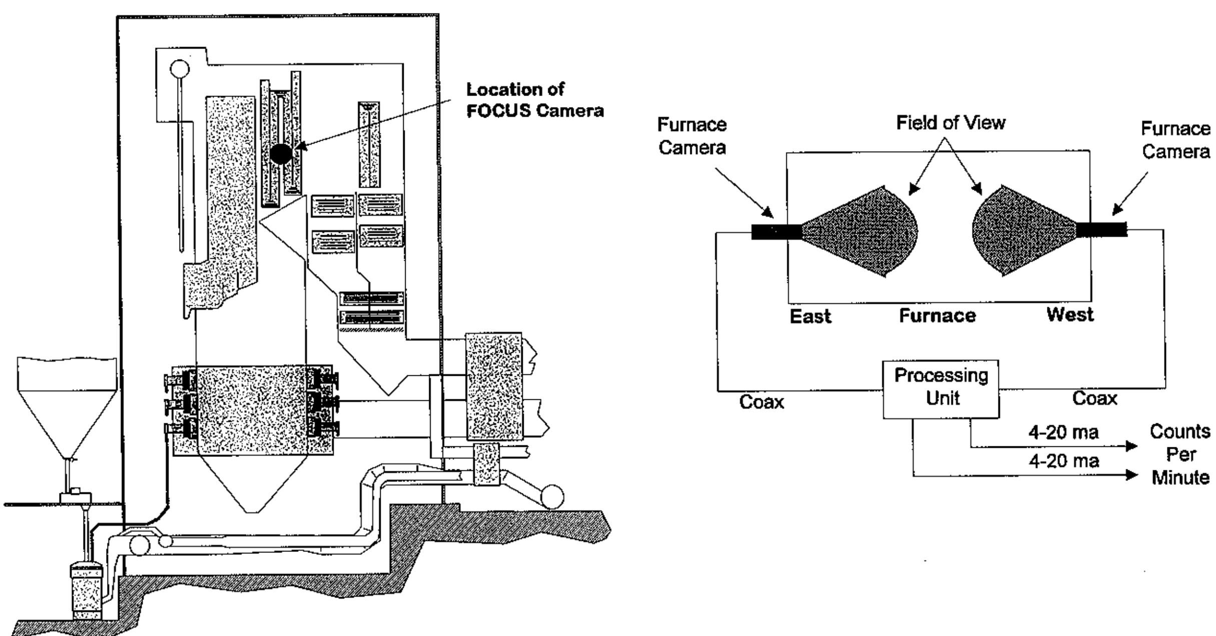

Figure 6. FOCUS General Arrangement

PHASE 4 - ADVANCED CONTROLS / OPTIMIZATION

As a result of the installations of the low NOx combustion systems at Hammond 4, combustion optimization has become significantly more difficult than prior to these retrofits. This added difficulty is a result of several factors including:

- Heightened concern and awareness of combustion conditions as a result of the passage of the 1990 Amendments to the Clean Air Act,
- Increased sensitivity of combustion conditions to process adjustments, and
- Additional complexity and more independent tuning adjustments.

The objective of this scope addition to the project at Plant Hammond is to evaluate and demonstrate the effectiveness of advance digital control/optimization methodologies as applied to the NOx abatement technologies installed at this site (LNB and AOFA). The major tasks for this project addition include: (1) design and installation of a distributed digital control system (DCS), (2) instrumentation upgrades, (3) advanced controls/optimization design and implementation, and (4) characterization of the unit both before and after activation of the advanced strategies. Major milestones for this phase of the Wall-Fired Project are shown in Table 3.

Table 3. Advanced Controls / Optimization Major Activities

Milestone	Status
Digital control system design, configuration, and installation	*Completed*
Digital control system startup	*Completed*
Instrumentation upgrades	*Completed*
Advanced controls/optimization design	In Progress
Characterization of the unit prior to activation of advanced strategies	Scheduled 8/94 - 4/95
Characterization of the unit following activation of advanced strategies	Scheduled Summer 1995

Combustion optimization is the procedure by which NOx reduction, combustion performance, and safety are balanced to achieve or approach a predetermined goal. In most instances, the goals are defined in terms of performance inequality constraints mutually agreed to by the burner vendor and the utility such as:

- NOx - Reduce to below guarantee value and/or compliance limit.
- Fly ash loss-on-ignition (LOI) - Hold below guarantee value and/or state imposed state utilization limit.
- Boiler performance - Maintain above the guarantee value.

These goals may be defined for one or more operating conditions. Only when all constraint goals are clearly met, will further NOx optimization be performed. Due the complexity of the combustion process, optimization is formidable unless the goals are lax. Combustion optimization for the low NOx burners with advanced overfire air is considerably more difficult than that required for setup of turbulent burners alone. This added difficulty is a result of the increase in the number of adjustments and sensitivity of these burners to operating conditions (Table 4).

Table 4. Combustion Tuning Control Points at Hammond 4

Pre-LNB+AOFA Retrofit	Post-LNB+AOFA Retrofit
Burners	Burners
Sleeve registers (24)	Sleeve registers (24)
Secondary air	Tip Positions (24)
Windbox balancing dampers	Inner registers (24)
Mill Biasing	Outer registers (24)
	Advanced overfire air
	Can-in-can dampers (8)
	Flow control dampers (4)
	Secondary air
	Windbox balancing dampers
	Boundary air
	Mill Biasing

Generally, optimization requires that the unit be taken out of economic dispatch and run at full-load for much of the optimization period. After balancing the secondary air flows, the burner optimization process is accomplished by adjusting the inner registers, outer registers, slide nozzles, and sleeve dampers while monitoring NO_x, O_2, and CO at the economizer outlet. When possible, burner adjustments of the same class (the classes being inner register, outer register, slide nozzle, or sleeve damper) are moved in unison to a nominal, optimized position. Only when flow and/or combustion irregularities dictate, are individual dampers adjusted from this nominal position. The adjustments to the sleeve dampers, inner registers, outer registers, and tip position are made during the burner optimization process and thereafter remain fixed unless changes in plant operation or equipment condition dictate further adjustments. The normal FWEC practice is to supply actuators on the sleeve dampers only. Optimization is performed for full-load operation and performance is checked at lower loads. Because of the constraints of the equipment and optimization methodology, the combustion process can be optimized for one operating condition (load, fuel condition, air distribution, etc.) and therefore is sub-optimal for all others.

Unlike SO_2 emissions which are primarily a function of the sulfur content of the fuel, NOx emissions are highly dependent on a number of parameters. Nitrogen oxides (NOx) are formed in combustion processes through the thermal fixation of atmospheric nitrogen in the combustion air producing "thermal NOx" and the conversion of chemically bound nitrogen in the fuel producing "fuel NOx". NOx emissions can theoretically be reduced by lowering: (1) the primary flame zone O_2 level, (2) the time of exposure at high temperatures, (3) the combustion intensity, and (4) primary flame zone residence time. NOx emission rates are strongly influenced by the apportionment of the air to the burners and AOFA system.

An example of the interdependencies and conflicting goals which must be considered can be seen in Figure 7. As shown, as excess air (or equivalently, excess oxygen) decreases, NOx decreases while LOI increases. High LOI values are indicative of poor combustion and therefore poor boiler performance. Also, on units which sell their fly ash (Hammond 4 does not at this time), an increase in fly ash LOI can change the fly ash from a marketable commodity to an undesirable byproduct. A decision must be made as to what is the optimum operating condition based on economic and environmental considerations. Similar compromises must also be made when optimizing boiler efficiency. In this case, the optimum operating condition is clear as long as the performance index is defined as boiler efficiency and other parameters (such as NOx emissions) are not considered. Conflicting objectives such as these have been observed on Hammond Unit 4. As shown in Figure 8, the NOx production rate is an increasing function of the excess oxygen level while fly ash LOI is a decreasing function. This data was collected during the short-term low NOx burner tests.

In addition to variations with excess oxygen levels and load, NO_X emissions also vary significantly during long-term operation and it is evident that a number of uncontrolled and unidentified variables greatly influence NO_X production. These influencing variables are believed to be mill operating conditions (primary air temperatures, air/fuel ratios, flows, grind, and moisture), secondary air non-uniformity (air register settings, forced draft fan bias, and windbox pressure differential), coal variability, etc. As shown in Figure 9, NOx long-term variability at Hammond Unit 4 for the LNB plus AOFA test phase was approximately 0.07 lb/MBtu at full load, increasing to 0.3 lb/MBtu at minimum load. As can be seen, there are significant differences in the NOx emission characteristics although no changes in burner adjustments or operating procedures were made during this time frame. A potential goal of any on-line optimization program installed at this site would be to drive NOx emissions down to the lower percentile and beyond.

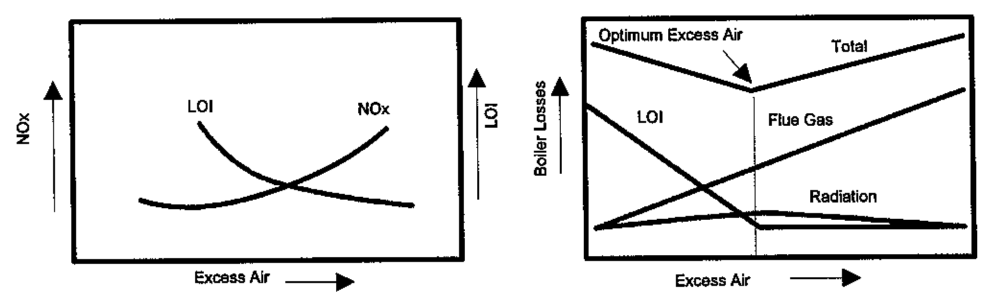

Figure 7. Typical Tradeoffs in Boiler Optimization

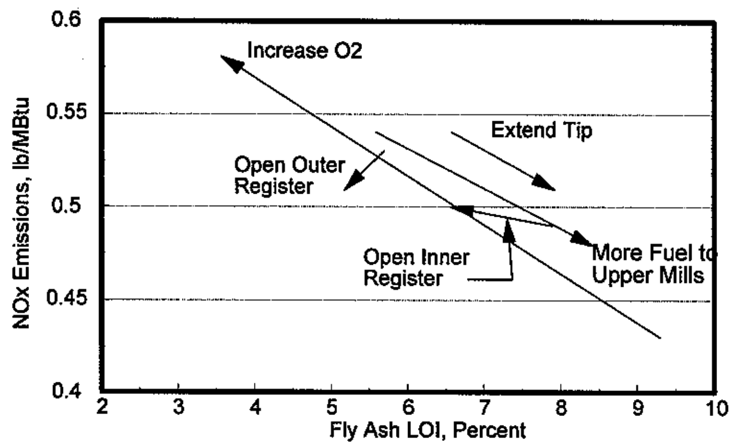

Figure 8. NOx and LOI vs. Excess Oxygen (NOx vs. LOI Tests)

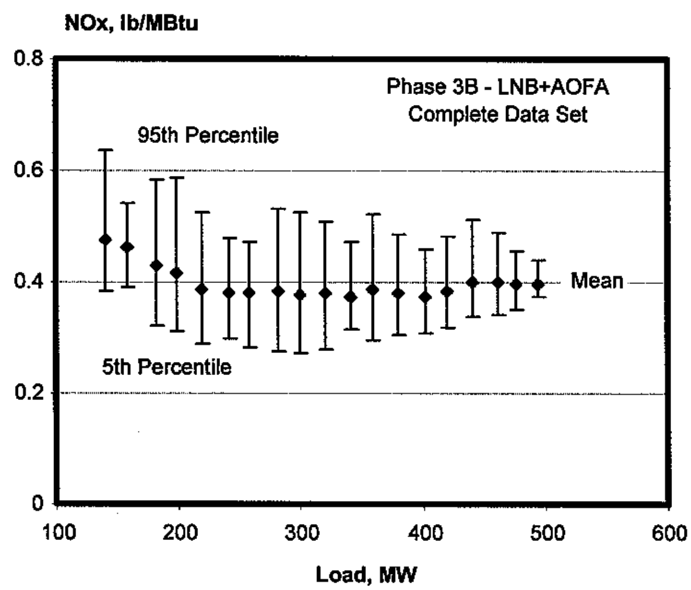

Figure 9. Long-Term NOx Emissions During LNB Plus AOFA Test Phase

Generic NOx Control Intelligent System

The optimization methodology to be demonstrated at Hammond is the *Generic NOx Control Intelligent System* (GNOCIS) whose development is being funded by a consortium consisting of the Electric Power Research Institute, PowerGen, The Southern Company, U.K. Department of Trade and Industry, and U.S. Department of Energy [7]. The objective of the GNOCIS project is to develop an on-line enhancement to existing digital control systems that will result in reduced NOx emissions, while meeting other operational constraints on the unit (principally heat rate and other regulated emissions). The main contractors for the development of GNOCIS are PowerGen and Southern Company Services. Commercializers for North America are SCS and Radian Corporation. In its role as commercializer, Radian is already deeply involved in the demonstrations in the U.S. PowerGen and one other as yet unnamed organization will be the commercializers in Europe.

The core of the system is a neural-network model of the combustion characteristics (such as NO_x emissions and fuel efficiency) of a boiler, that reflects both short-term and longer-term shifts in boiler emission characteristics. The software applies an optimizing procedure to identify the best set points for the plant. The recommended set points are conveyed to the plant operators via the DCS or, at the plants discretion, the set points can be implemented automatically without operator intervention. The software incorporates sensor validation techniques and is able to operate during plant transients (i.e. load ramping, fuel disturbances, and others). Figure 10 shows the major elements of GNOCIS.

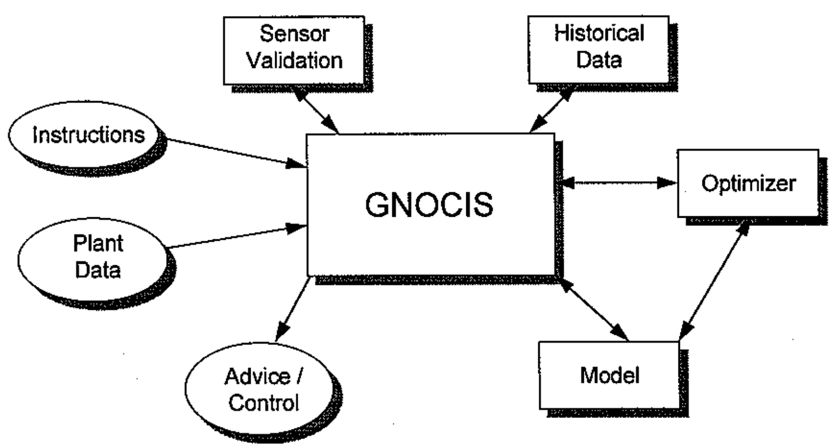

Figure 10. Major Elements of GNOCIS

Following an initial feasibility study in which several promising methodologies were evaluated, a software package from Pavilion Technologies was selected to fulfill the "core" technology role in GNOCIS, i.e. to form the basis of the process and control models necessary to perform on-line optimization. The models are created from data collected from long-term, normal operation, augmented as necessary by short-term testing.

GNOCIS methodology is now undergoing testing at PowerGen's Kingsnorth Unit 1 (a 500 MW tangentially-fired unit with an ICL Level 3 Low NOx Concentric Firing System) and Alabama Power's Gaston Unit 4 (a 250 MW B&W unit with B&W XCL low NOx burners), the results of which have been reported elsewhere [8].

Customization of GNOCIS at Hammond is now underway. The major activities associated with the GNOCIS installation at Hammond 4 are:

- Digital Control System Design, Configuration and Installation
- Instrumentation Upgrades
- Pre-Installation Testing
- Model and Optimization Strategy Development
- Post-Installation Testing

These elements are discussed in the following paragraphs.

Digital Control System Design, Configuration, and Installation

An integral part of Phase 4 of the project was the design and installation of a digital control system (DCS) to be the host of the advanced control/optimization strategies being developed. Prior to the installation of this DCS, Hammond Unit 4 utilized a pneumatic boiler control system which would be unsuitable for a closed-loop implementation of GNOCIS, therefore it was necessary to upgrade this system. SCS Engineering and Georgia Power had overall responsibility for the following major activities associated with this task:

- Preliminary engineering,
- Procurement,
- Detail engineering,
- Digital control system configuration, and
- Installation and checkout.

In total, the digital control system was configured for 2352 input/output points consisting of 572 analog inputs, 116 analog outputs, 1032 digital inputs, and 632 digital outputs with the balance being allocated spares. This system is designed such that the I/O is fully distributed and operator interaction with the digital control system is almost exclusively through the operator display -- there are no benchboard mounted manual/auto stations or switches.

An overview of the digital control system is shown in Figure 11. Based on a competitive evaluation, a Foxboro I/A system was selected for installation. The milestones in the design, installation, and startup of the Hammond Unit 4 digital control system are shown in Table 5.

As part of this project, the control room was modified to accept the new Unit 4 digital control system. Pre-existing Unit 4 benchboards were removed and replaced with a CRT based control panel. In addition to the upgrades to Unit 4, Georgia Power has upgraded Unit 3 and is also considering upgrading the digital control systems on Units 1 and 2. Digital control system and control room modifications for Units 1, 2, and 3 are not a part of the Wall-Fired Project.

The Unit 4 DCS has been interfaced with the other DCS's at the site. Unit 3, Unit 4, and Electrical DCS systems are connected through a dual-redundant IEEE 802.3 (Ethernet) local area network (LAN). Through this LAN, the three DCSs are able to share process information and graphics. If for some reason either the A or B LAN fails, all DCSs can maintain normal operation. An additional benefit of these LANs are the ability to share costly resources such as engineering consoles, historical drives, etc. In addition to the inter-DCS network, the Unit 4 DCS (and the others also), are connected through a router to the plant's token-ring PC engineering and administrative LAN and the corporate wide area network (WAN) (Figure 12). The latter enables remote access of process data and facilitates software maintenance. A Sun Sparcstation 5, hosting the GNOCIS software, is connected to this network. The router isolates the DCS from the plant LAN and company WAN.

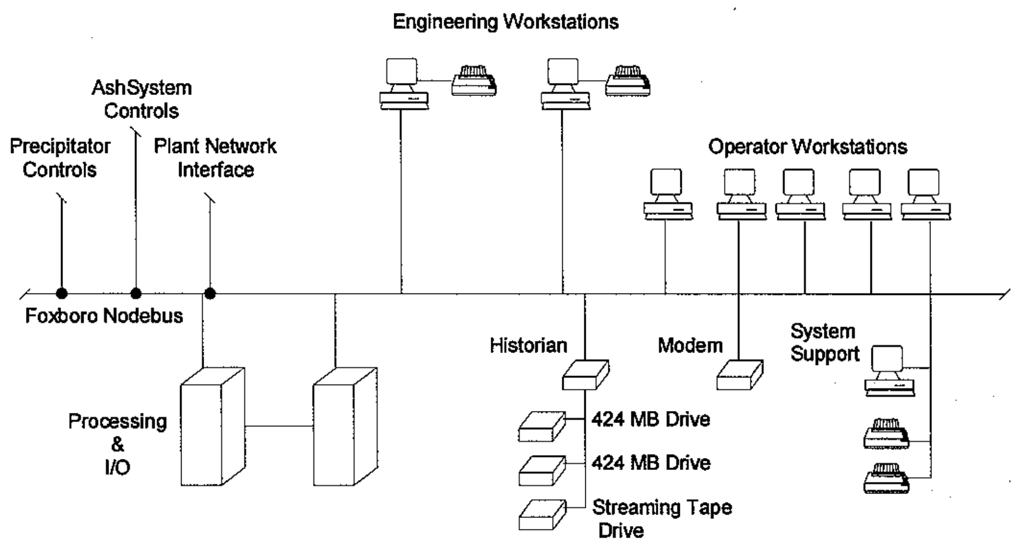

Figure 11. Hammond Unit 4 DCS Overview

Table 5. DCS Installation Milestones

Date	Milestone
June 1992	• Begin preliminary engineering
August 1992	• Issue request for proposals for digital control system
February 1993	• Foxboro I/A system received at SCS
April 1993	• Issue purchase order to Foxboro
June 1993	• Start detail engineering
June 1993	• Begin configuration
January 1994	• Configuration complete
	• Start checkout
February 1994	• Foxboro I/A system shipped to Plant Hammond for installation
May 1994	• Installation complete
June 1994	• Unit Startup

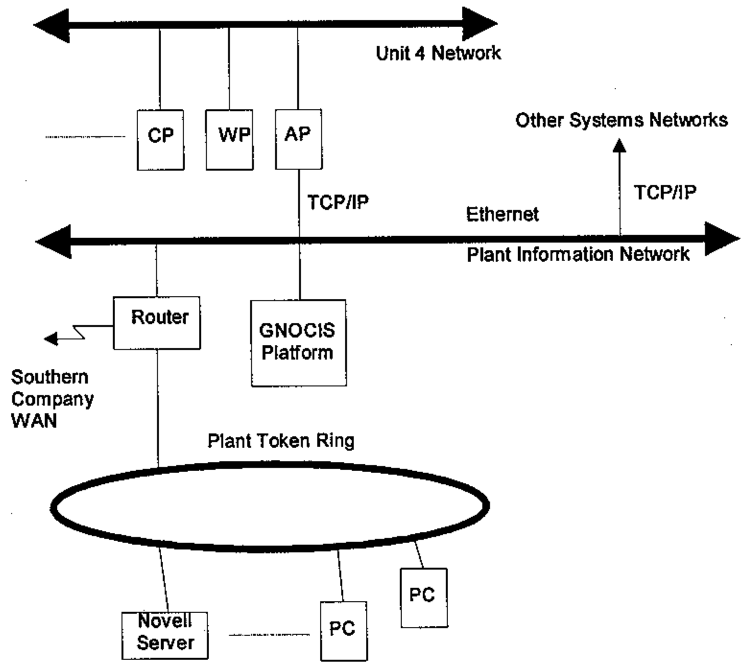

Figure 12. Hammond Plant Network

Pre-Installation Testing

One prerequisite of a GNOCIS installation is the availability of substantial and high quality process data from the host site. At Hammond, this need was amplified in that a goal of the project is to comprehensively test the performance of GNOCIS. Short-term diagnostic testing was conducted during August 1994 and March 1995, and more comprehensive performance testing was undertaken in November 1994. The primary objectives of these tests were to:

- Re-characterize the unit following a number of combustion modifications during the most recent outage,
- Establish relationships between control variables and measured variables,
- Establish the impact of off-design operational settings, and
- Augment the database used for training of GNOCIS models.

Based on these tests, NOx emissions were found to be approximately 0.43 lb/MBtu -- slightly higher that 0.40 lb/MBtu observed during Phase 3B testing -- with corresponding fly ash loss-on-ignition levels near 8 percent. This latter value is similar to what had been observed during Phase 3B testing.

Long-term collection of data to be used for training for this phase has been in progress since summer 1994. Although this represents a large volume of information and satisfactory GNOCIS models could potentially be developed using a subset (one to two months) of this long-term, normal operating data only, it was felt that by obtaining process information in off-design conditions, the combustion models would be more robust. The need to conduct additional testing depends on the variability of data contained in the training set. Unfortunately, although having many advantages otherwise, digital control systems tend to create highly correlated data in which it is difficult to ascertain emission sensitivities to a number of potential control parameters. One example where this is likely is in mill loadings. Typically, when in service and in automatic, all mills are constrained to equal fuel flows and therefore, unless there is some variability, models can not be created based on process data alone, that can estimate the impact of individual mill flows on important combustion properties such as NOx emissions. The short-term test suite was planned to artificially create the off-design operating conditions that may not be seen during normal unit operation.

Model and Optimization Strategy Development

Retrieval of process data from the digital control system is now in progress and initial modeling efforts have begun. The first step in the design process is the development of suitable predictive models. An example of the results from a typical non-linear predictive model of NOx and carbon-in-ash are shown in Figures 13 and 14, respectively. In this example, the inputs to the network were coal flows, excess O_2, and overfire air flows. The data collected from the DCS and used in training was five minute averages. Steps which could have been taken to improve the prediction capabilities include the addition of more process data and time averaging. Due to the long response time of the on-line carbon-in-ash devices, especially at reduced loads, the modeling of this parameter is generally much more difficult than modeling NOx emissions.

Although predictive models are useful in a number of circumstances, what is required of GNOCIS are control models. Considerations in control model development are sensitivities of model outputs (such as boiler efficiency and NO_x emissions) to available inputs, and control points readily changeable by the operator or through the DCS.

Design of the control strategy for Hammond 4 is now in progress. As a starting point, it is planned to used the control variables as shown in Table 6. The control variables in the first tier will be implemented initially, and, if successful, additional variables from the subsequent tiers will be considered if their inclusion improves the performance of the system significantly. Software hooks have been designed into the DCS to facilitate the incorporation of these signals into the control logic.

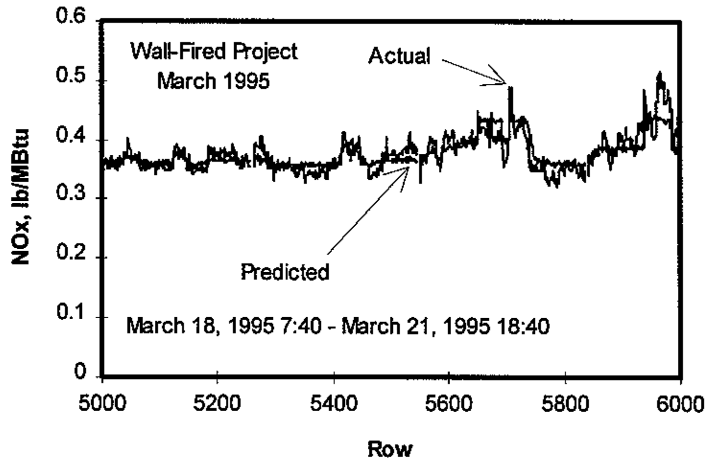

Figure 13. NOx Predictive Model

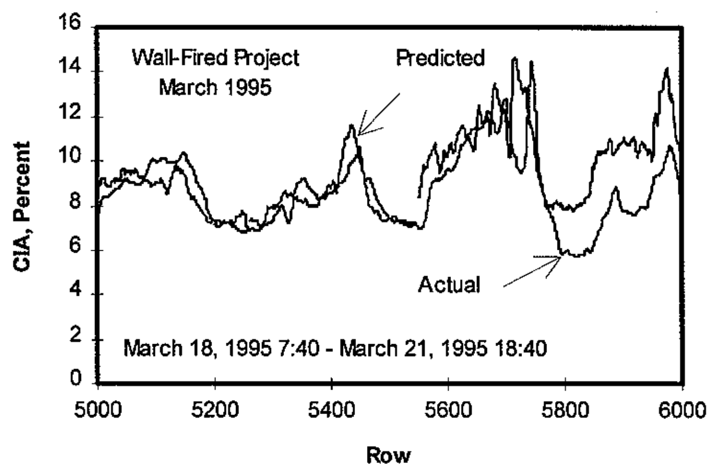

Figure 14. Carbon-in-Ash Predictive Model

Table 6. Planned Control Variables

Parameter of Interest	Controlled Parameter	Advisory Mode Open-Loop	Supervisory Mode Close-Loop
First Tier			
Overall Furnace Air / Fuel Ratio	Excess O_2 Bias	Y	Y
Overall Furnace Staging	AOFA Flow (4)	Y	Y
AOFA Distribution	AOFA Flow (4)	Y	Y
Mill Biasing	Mill Coal Flow (6)	Y	Y
Mills-in-Service	Mill Coal Flow (6)	Y	Advise
Second Tier			
AOFA Distribution	AOFA Can Dampers (8)	Y	Y
Furnace Secondary Air Distribution	Burner Sleeve Damper s by Banks (8)	Y	Y
Third Tier			
Furnace Secondary Air Distribution	Burner Sleeve Damper s (24)	Y	Y

Using the combustion models thus developed, predictions can be made as to the benefits that can be obtained by the application of GNOCIS. For example, as shown in Figure 15, *predicted* CIA levels near 5 percent were achieved using optimized control setpoints (fuel biasing, excess O_2, overfire air flow rates). The corresponding recommended excess O_2 levels are shown in Figures 16 and 17. Although the recommended setpoints may not be feasible for actual long-term operation, this scenario does at least lend hope that opportunities may be present for significant CIA reductions. *Again, these are predicted results, and although encouraging, they need to be substantiated with thorough plant testing.*

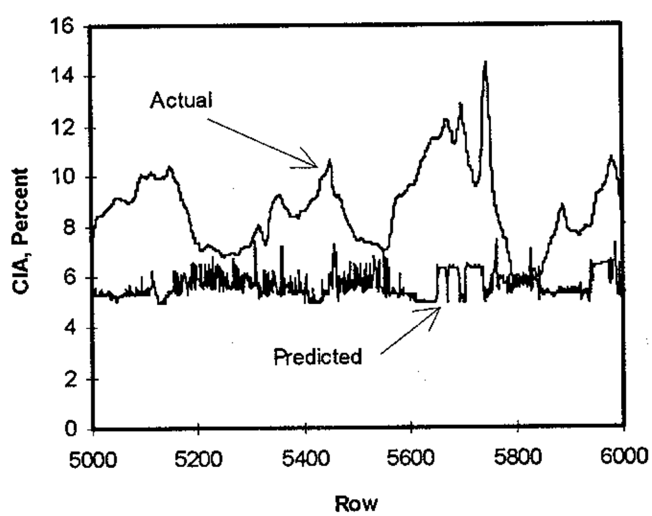

Figure 15. Control Model - Predicted CIA Output (Preliminary)

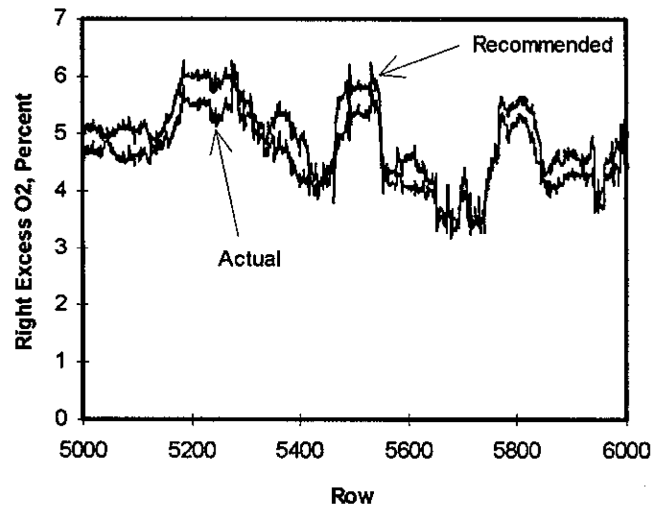

Figure 16. Control Model - Recommended Right Excess O_2 (Preliminary)

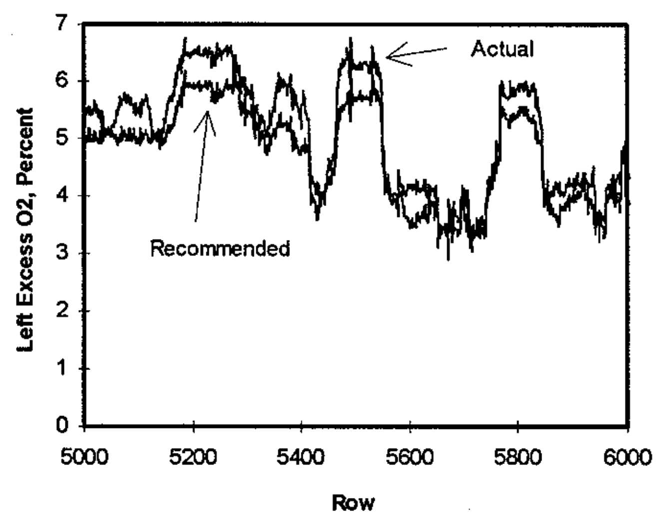

Figure 17. Control Model - Recommended Left Excess O_2 (Preliminary)

Post-Installation Testing

Testing of GNOCIS is scheduled to commence summer 1995 in both open-loop-advisory and close-loop-supervisory modes. The test program is now scheduled for completion during third quarter 1995.

SUMMARY

Work is still in progress at Hammond Unit 4. A summary of the current status and plans for this site are as follows:

- Long-term data set collected and it is now being filtered to remove bad and irrelevant data,
- Predictive and control model development is in progress,
- The GNOCIS software is being installed on the Sun Sparcstation 5 and interfaced with the DCS,
- Operator displays are being developed and integrated into the operator consoles, and
- Open- and closed-loop testing of GNOCIS at Hammond 4 is scheduled to commence summer 1995.

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DEMONSTRATION OF GAS REBURNING-SORBENT INJECTION TECHNOLOGY FOR NO_x/SO_2 EMISSION CONTROL

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Denver Colorado

ABSTRACT

Under the DOE Clean Coal Technology Program, EER successfully applied gas reburning and sorbent injection technologies (GR-SI) to both tangentially-fired and cyclone-fired utility boilers. In each case, emission reductions exceeding the program goals were demonstrated with no significant detrimental impacts on the boiler operation. All testing and evaluation have been completed and both host utilities have elected to purchase the GR-SI equipment for future use.

This paper presents the results of the long-term evaluation of GR-SI technology on both units. In addition, an economic comparison with competing NOx/SOx control technologies is presented accompanied by plans for commercial deployment.

INTRODUCTION

As part of the U.S. Department of Energy's Clean Coal Technology Program (Round 1), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically NO_x and SO_2. The project involved operating combined gas reburning and sorbent injection (GR-SI) on two coal-fired utility boilers to determine the reductions in these boiler emissions. Gas reburning (GR) controls the emissions of NO_x by staged fuel combustion, which involves the introduction of natural gas into the flue gas stream. Sorbent injection (SI) consists of the injection of dry, calcium-based sorbents into the flue gas to achieve SO_2 capture. Several benefits are derived from utilization of the combined GR-SI technologies including the following:

- Low capital cost relative to more expensive scrubbers
- Compatibility with high-sulfur coal
- No adverse effects on boiler thermal performance
- Minimal system operating complexity

The first demonstration was performed at Illinois Power's Hennepin Unit 1, located in Hennepin, Illinois. This unit is a 71 MWe tangentially-fired boiler that uses high-sulfur Illinois coal. The second test was performed at City Water Light & Power's (CWLP) Lakeside Unit No. 7, located in Springfield, Illinois. This unit is a 33 MWe cyclone-fired boiler that also uses high-sulfur Illinois coal. Targets for the project at both sites were reductions of 60 percent in NO_x emissions and 50 percent in SO_2 emissions.

TECHNOLOGY DESCRIPTION

Gas Reburning

Gas reburning involves reducing the levels of coal and combustion air in the burner area and injecting natural gas above the burners followed by the injection of overfire air (OFA) above the reburning zone as shown in Figure 1. This three-zone process creates a reducing area in the boiler furnace within which NO_x created in the primary zone is reduced to elemental nitrogen and other less harmful nitrogen species. Each zone has a unique stoichiometric ratio (ratio of air to that theoretically required for complete combustion) as determined by the flow of coal, burner air, natural gas, and OFA. Flue gas recirculation (FGR) may be used to provide momentum to the natural gas injection. Although FGR has a low O_2 content, it also has a minor impact on reburning and burnout zone stoichiometries. The descriptions of the zones are as follows:

- Primary (burner) Zone: Coal is fired at a rate corresponding to 75 to 90 percent of the total heat input, under low excess air. NO_x created in this zone is limited by the lower heat release and the reduced excess air level.

- Reburning Zone: Reburning fuel (natural gas in this case) injection creates a fuel rich region within which methane breaks down to hydrocarbon fragments (CH, CH_2, etc.) which react with NO_x, reducing it to atmospheric nitrogen. The optimum reburning zone stoichiometry is 0.90, achieved by injecting natural gas at a rate corresponding to 10 to 25 percent of the total heat input.

- Burnout (exit) Zone: Overfire air is injected higher up in the furnace to complete the combustion. OFA is typically 20 percent of the total air flow; a minimum excess air of 15 percent in maintained. OFA injection is optimized to minimize CO emissions and unburned carbon-in-fly ash.

Ambient air is used to cool the gas injection nozzles when the gas reburning system is not in operation. The GR-SI system is controlled by a Westinghouse Distributed Process Family system (WDPF). The WDPF provides integrated modulating control, sequential control and data acquisition for a wide variety of system applications. All start/modulation/stop operations are performed in the control room using a keyboard-CRT with custom graphics.

Sorbent Injection

Sorbent injection technology controls SO_2 emissions through injection of a calcium-based sorbent such as hydrated lime [$Ca(OH_2)$] into the boiler furnace where it reacts with gaseous SO_2 to form solid calcium sulfate. This compound is then removed from the flue gas in the electrostatic precipitator.

Sorbent is transported from a storage silo to the boiler and introduced into the flue gas through injection nozzles. A flow splitter in the sorbent line equally distributes the sorbent to the nozzles. To obtain the optimum sorbent mass flow and nozzle velocities required for adequate boiler dispersion, additional injection air is provided from a booster fan. Ambient air is used to cool the nozzles when the sorbent system is not in operation.

GR-SI Integration

Gas reburning and sorbent injection are applied simultaneously to achieve combined NO_x and SO_2 control. Although significantly reducing the NO_x emissions, gas reburning also achieves an incremental reduction in SO_2 emissions, since natural gas contains no sulfur. This complements the SO_2 reduction of the sorbent injection process and reduces the amount of sorbent otherwise required.

HISTORICAL PERSPECTIVE

The development of gas reburning technology has been underway in various laboratories since the 1970's. EER, with the support of the EPA and GRI, began extensive bench and pilot-scale testing in 1981 to characterize the fundamental process variables. These tests provided valuable scale-up information needed for the development of commercial applications under industrial conditions.

Sorbent injection has been undergoing development since the mid-1970's with funding from EPA, DOE, EPRI and several commercial firms. Most of the work has focused on identifying the process parameters used to optimize sulfur capture. This work included laboratory scale reactivity tests and pilot-scale testing that focused on the system design and impacts to the boiler. A number of field evaluations have been completed and additional efforts are in progress. EER has participated both directly and indirectly in most of this development work.

EER's gas reburning-sorbent injection projects at Illinois Power and City Water Light & Power were part of the U.S. Department of Energy's Clean Coal Technology Round 1 Program. The goal of the project was to demonstrate that combined GR-SI could be successfully incorporated into both tangentially-fired and cyclone-fired boilers while achieving significant reductions in NO_x and SO_2 emissions. The total value of the project was $37.5 million. Awarded in July of 1987, the project will be successfully completed at the end of 1995.

<u>Project Schedule and Status</u>

The project was divided into the following three phases:

- Phase I Design and Permitting
- Phase II Construction and Startup
- Phase III Operation, Data Collection, Reporting and Disposition

The initial format of the project involved three sites, the two described above and Central Illinois Light Company's Edwards Station. During Phase I, it was determined that the cost to upgrade the Edwards electrostatic precipitator to accommodate sorbent injection was beyond the scope of the project budget. Therefore, the Edwards site was eliminated from further activity.

The schedule for the project is shown in Figure 2. The project was awarded in July, 1987. Phase I activity for the three sites was perform concurrently; however, both construction and testing at Lakeside lagged that at Hennepin in order to transfer experience from site to site.

Testing at both sites has been completed and the final report the Hennepin site has been released. The final report for the Lakeside site is in progress.

The gas reburning system at Hennepin was retained by Illinois Power. Both the gas reburning and sorbent injection systems at Lakeside were retained by CWLP.

Process Design

The process design was performed during Phase I of the Project. The goal in the design of the GR-SI system was to achieve the emissions control objectives while minimizing impacts on other areas of unit performance. Using NO_x reduction and sorbent sulfation reaction modeling and isothermal physical flow modeling, the process stream inputs and injection details of the GR-SI system were finalized. Heat transfer modeling was then conducted to predict the impacts on heat absorptions by each heat exchanger and steam side and gas side temperatures. Also evaluated were the potential effects on various areas of boiler performance including fuel burnout, furnace slagging, waterwall wastage, and ESP performance. As a result of the process design effort, the following parameters were established:

- Natural gas, overfire air and sorbent injector sizes, required numbers, and boiler locations.

- Volume flow rates for natural gas, flue gas recirculation, overfire air, sorbent, and sorbent injection air.

- Flue gas recirculation and sorbent injection air fan specifications.

- Initial operating set-points for optimum boiler stoichiometries.

At each of the two demonstration sites, special design considerations were required to handle unique conditions in the boiler. At Illinois Power's tangentially-fired unit, humidification of the exit flue gas was required in order to raise the resistivity of the fly ash, thereby improving the efficiency of the electrostatic precipitator. Also, a CO system was installed to adjust the pH of the ash prior to its discharge into the collection pond.

CWLP's cyclone-fired boiler operates in a pressurized environment requiring check valves in the natural gas, sorbent and injection air ducts to prevent backflow of flue gas. Sealing air was also integrated with boiler penetration equipment. Due to the age of the sootblowers and wallblowers and the anticipated increase in use, this equipment was replaced. CWLP's ash pond was nearing capacity; therefore, a dry ash handling system was installed to provide for off-site removal.

Installation and Integration

The GR-SI system was installed during Phase II of the Project. The gas reburning system retrofit involved routing a natural gas main to the boiler, installing a flue gas recirculation fan, installing a multiclone dust collector to remove particulate and protect the fan, and connecting the equipment with ductwork. The overfire air system involved installation of ductwork from the secondary air system to the injection nozzles. The sorbent injection system included a sorbent storage silo, feed equipment and transport system. Penetration of the sorbent into the boiler was enhanced by installing an injection air fan system. An extensive plant outage was required to install boiler penetrations. Some outage time was also required to install the control system.

Integration of the GR-SI system into normal boiler operations required modification and/or replacement of the existing control system. The new control system was designed to accommodate several operating conditions including gas reburning, sorbent injection, combined gas reburning-sorbent injection, non-operation of either system, and operation of site-specific additional equipment.

Test Plan and Testing

Phase III of the Project was devoted to demonstration of the technology. Following startup, a series of pre-planned parametric tests were performed independently on the gas reburning and sorbent injection systems. These tests were conducted at different boiler load conditions and involved varying operational control parameters (such as boiler zone stoichiometries, natural gas heat input, flue gas recirculation flow rate, overfire air flow rate, sorbent feed rate, etc.) and assessing the effect on boiler emissions and thermal efficiency. Following the parametric testing, the technologies were integrated through a series of optimization tests, incorporating the set points established in the parametric tests. Final adjustments to the control parameters were made as required.

A one-year duration long term testing program was performed in order to judge the consistency of system outputs, assess the impact of long-term operation on the boiler equipment, gain experience in operating GR-SI in a normal load-following environment, and develop a database for use in subsequent GR-SI applications. The project concluded with a test of alternate sorbent material.

TEST RESULTS

Emissions

EER conducted a comprehensive test demonstration program at each of the two sites, operating the equipment over a wide range of boiler conditions. Over 1500 hours of operation were achieved enabling EER to obtain a substantial amount of data. Intensive measurements were taken to quantify the reductions in NO_x and SO_2 emissions, the impact on boiler equipment and operability, and all factors influencing costs. The results showed that GR-SI technology achieved excellent emissions reductions on both tangentially-fired and cyclone-fired boilers; all goals of the project were achieved. The following table summarizes the results of the combined gas reburning-sorbent injection operation:

	Tangential	Cyclone
NO_x emissions		
baseline	.75 lb/MMBtu	.95 lb/MMBtu
optimized reduction	75%	74%
average reduction	67%	66%
average gas heat input	18%	22%
SO_2 emissions		
baseline	5.3 lb/MMBtu	5.9 lb/MMBtu
average reduction	53%	58%
calcium-to-sulfur ratio	1.75	1.8
calcium utilization	24%	24%

The results are presented in detail in Figures 3 thru 8. Figure 3 presents the relationship between NO_x emissions and percent of gas heat input for the two units. The data shows that NO_x decreases as the reburning gas heat input increases. Also, as shown in Figures 4 and 5, the performance goal (reduction of NO_x emissions by 60%) on both units was consistently met throughout the test program. The slope of the curve for the tangentially-fired unit tends to flatten out at the higher gas heat inputs, while the slope for the cyclone-fired unit shows continued NO_x reduction due to its shorter reburning zone residence time.

A higher gas heat input is required for the cyclone-fired boiler than the tangentially-fired boiler. On the T-fired boiler, the stoichiometry in the firing zone is reduced to promote reduction in NO_x emissions. This method is not the applicable to cyclone-fired boilers since reducing the stoichiometry disrupts the slagging characteristics of the cyclone. Therefore, a higher gas heat input was required to achieve the same NO_x emissions reduction. As the above table shows, other factors remained approximately the same.

The gas reburning systems for these units used flue gas recirculation to enhance the penetration and mixing of the reburning gas. While high velocity gas jets could have been used instead of FGR, FGR was selected as the more conservative approach for these initial demonstrations since the penetration and mixing are controlled by the FGR flow rate essentially independent of the natural gas flow rate. However, FGR adds substantially to the capital cost of the GR system and also contributes slightly to the increased superheat attemperation rate. To demonstrate this condition, EER removed the FGR system from a similar gas reburning demonstration conducted on a wall-fired boiler and installed high-velocity injectors. As anticipated, the modifications had no impact on NO_x emissions reductions achieved with FGR. The economic effect is substantial; on future units a significant capital cost savings can be achieved by eliminating the FGR in favor of high-velocity injectors.

Figure 6 presents the relationship between SO_2 and calcium-to-sulfur molar ratio. The results show that the reduction in SO_2 emissions improves with higher Ca/S. Also, as shown in Figures 7 and 8, the performance goal (reduction of SO_2 emissions by 50%) at both units was consistently met throughout the test program. The Lakeside unit experienced a higher SO_2 emissions reduction than the Hennepin unit due to a higher level of gas heat input.

Higher levels of Ca/S were required at lower loads due the effect of temperature on the sulfation reaction. Bench tests showed that a temperature of 2200°F was optimum to achieve the maximum SO_2 emissions reduction. This temperature was observed in the sulfation zone during full load, but was somewhat less at lower loads.

The GR-SI demonstration was conducted primarily with a conventional sorbent, Linwood hydrated lime. At the conclusion of the long term testing, three advanced sorbents prepared by EER and the Illinois State Geological Survey Department were also evaluated. Two sorbents containing agents to facilitate sulfation (designated PromiSORB™ A and PromiSORB™ B) were prepared through an EER-Petroleos de Venezuela joint venture. The third sorbent, High Surface Hydrated Lime (HSAHL), was also tested. At a nominal Ca/S molar ratio of 1.75, the following results were achieved:

Sorbent	SO_2 Capture	Utilization
PromiSORB™ A	53%	31%
PromiSORB™ B	66%	38%
HSAHL	60%	34%

The maximum SO_2 capture measured was 81% at a Ca/S ratio of 2.59 using PromiSORB™ B. This material yielded outstanding performance, demonstrating the highest sorbent utilization ever measured in a full-scale sorbent injection test. The impact is a significant reduction in the mass flow of sorbent required to achieve a given SO_2 emissions limit. There was also a corresponding reduction in the volume of ash disposal, boiler fouling and sootblower usage frequency.

Boiler Impacts

Although boiler stoichiometries were altered as an inherent requirement of gas reburning and the frequency of sootblower operation was increased due to sorbent injection, no adverse effects on either boiler efficiency or equipment were observed.

Gas reburning operation resulted in minimal impact on the heat absorption profile. As a result, steam temperatures also showed minimal variation. However, with sorbent injection, the thermal performance was affected by the increase in particulate loading through the upper furnace and convection pass. With increased use of sootblowers, this condition was alleviated, although there was also a slight increase in steam attemperation rate. The boiler efficiency decreased by approximately 1% during gas reburning due moisture in the fuel and increase in heat loss due to moisture formed in combustion. Note that a higher flue gas moisture content results from firing natural gas which has a higher hydrogen-to-carbon ratio than coal.

In order to gage the structural impact on the boiler due to operation of the GR-SI system, a series of visual and instrumented inspections were performed both prior to and after testing. The test results were used to determine the existence of degradation and/or equipment failures and assess the wear rates. Of particular interest were the boiler tubes and electrostatic precipitator.

The boiler tubes were examined for tube wear, metallurgical change, and slagging/fouling. All conditions were found to be acceptable. There was no significantly measurable wear of tubes as a result of GR-SI operation. Also, when projecting the life of the tubes, analysis indicated that the scheduled life of the boiler was not compromised either with or without continued use of the GR-SI system.

The precipitator was inspected both before and after testing. The inspections concluded that the precipitator had adequately accommodated the changes in ash loading and resistivity with the presence of sorbent in the ash. During testing, the precipitator was evaluated for particulate matter loading, fly ash resistivity and inlet duct temperature distribution. No adverse conditions were found to exist.

COMMERCIAL APPLICATIONS

The gas reburning-sorbent injection project has demonstrated the success of these technologies in reducing NO_x and SO_2 emissions. Utilizing the process design conducted early in the project with the vast amount of data collected during the testing, EER has developed a database of information necessary to apply the technologies to all major firing configurations (tangential, cyclone and wall-fired) on both utility and industrial units. The emissions control and performance can be accurately projected as can the capital and operating costs. Gas reburning-sorbent injection technology has now been developed to the point that it can be offered by EER on commercial terms.

Economic Considerations

Economic considerations are a key issue affecting technology development. Application of gas reburning-sorbent injection requires modifications to existing power plant equipment. As a result, the capital costs and operating costs depend largely on site-specific factors such as:

- Gas availability at the site
- Coal-gas cost differential
- Sulfur dioxide removal requirements
- Value of SO_2 allowances

Based on the results of this project, EER expects that most gas reburning installations will achieve at least 60% NO_x control when firing 15% gas. The capital cost estimate for installing a gas reburning system on units of 100 MW and larger is in the range of $15/kw plus the cost of a gas pipeline (if required). Operating costs are almost entirely related to the differential cost of the gas over the coal as reduced by the value of SO_2 emissions reduction (due to the zero sulfur content of natural gas). Other operating cost factors are related to reductions in ash, mill power and maintenance, and a minor reduction in boiler efficiency, typically 0.0 to 1.0%.

In comparison to scrubbers, sorbent injection achieves slightly lower SO_2 control and somewhat higher operating cost, but with capital costs about one-fourth that of wet scrubbers. The capital cost estimate for a sorbent injection system is $50/kw. Operating costs are dominated by the cost of the sorbent and sorbent/ash disposal costs. At present, the cost of SO_2 control via sorbent injection exceeds the value of SO_2 allowances in most cases. However, as allowance costs rise into the $300/ton range, SI will be competitive.

SUMMARY

The following results can be highlighted from these gas reburning-sorbent injection demonstrations:

- GR-SI can be installed and operated successfully on both tangentially-fired and cyclone-fired boilers

- The project goals of 60% NO_x reduction and 50% SO_2 reduction were exceeded at all boiler loads

- The system was operated consistently and reliably

- The system demonstrated no significant thermal impact

- CO can be controlled by exit stoichiometry

- Existing boiler equipment experienced no mechanical degradation or failure

ACKNOWLEDGMENTS

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- Gas Research Institute
- Illinois Department of Energy and Natural Resources
- Illinois Power Company
- City Water Light & Power of Springfield, Illinois
- Energy and Environmental Research Corporation

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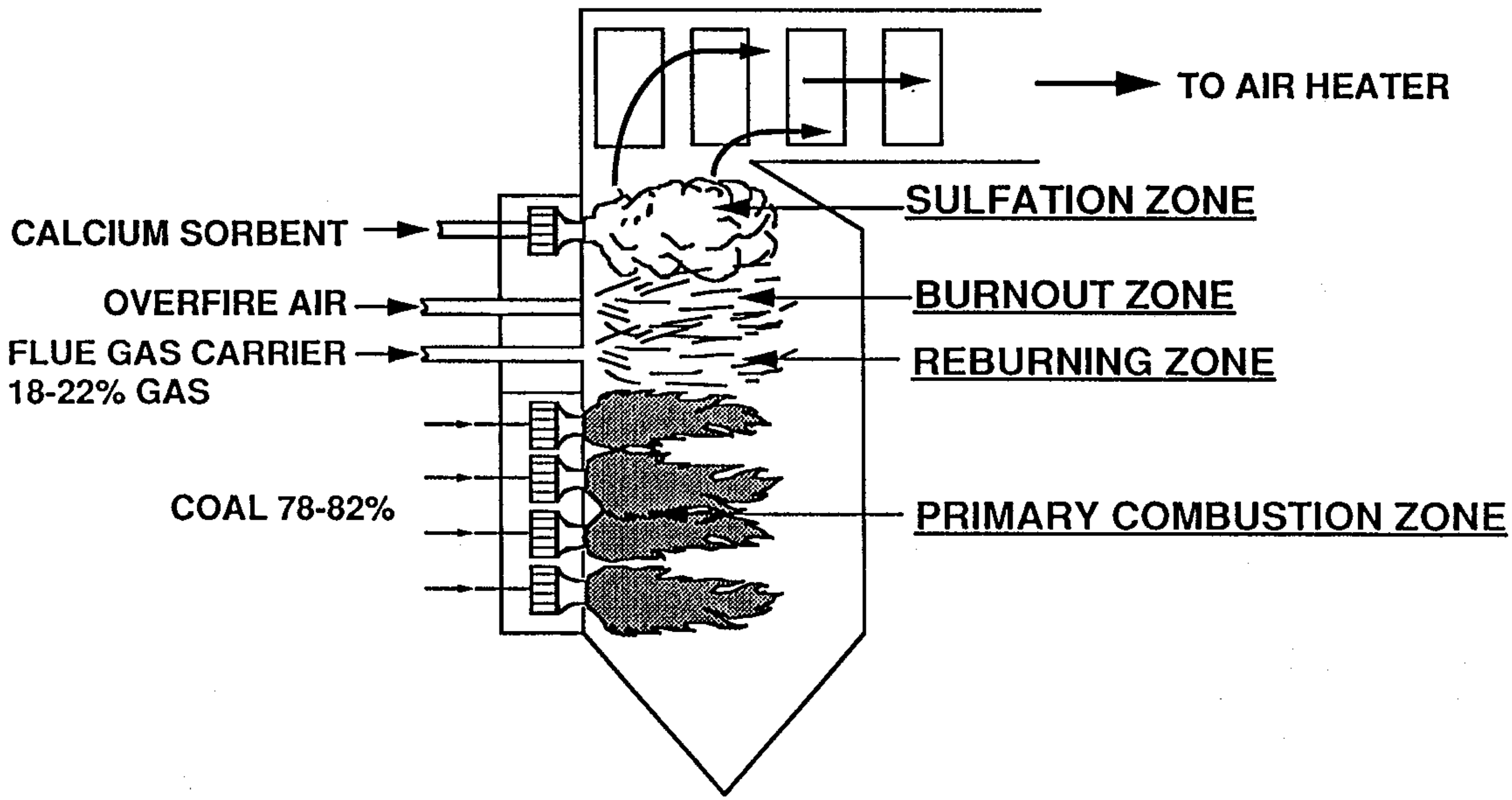


Figure 1. Schematic of Gas Reburning-Sorbent Injection System

Enhancing the Use of Coals by Gas Reburning-Sorbent Injection
Project Schedule

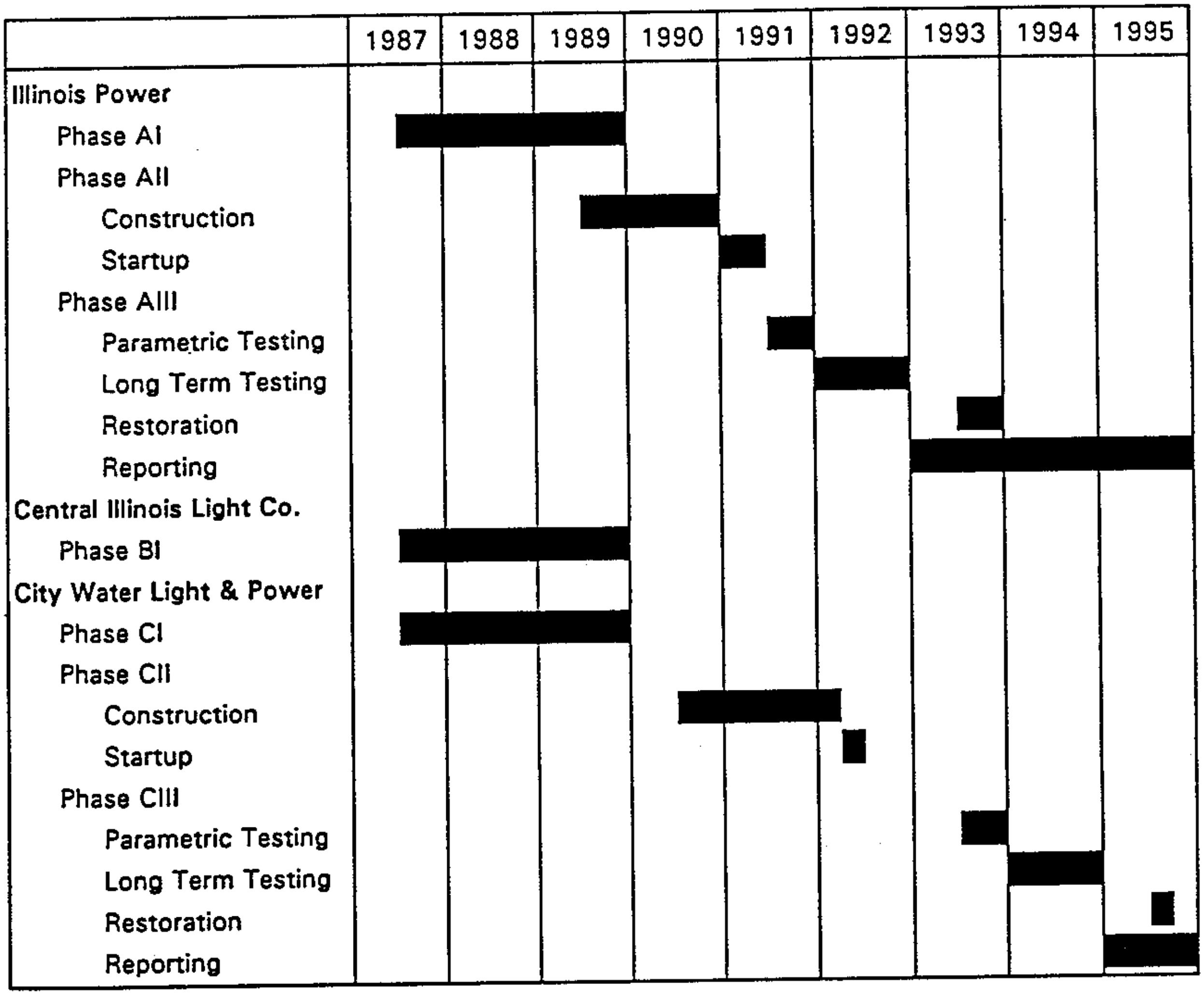
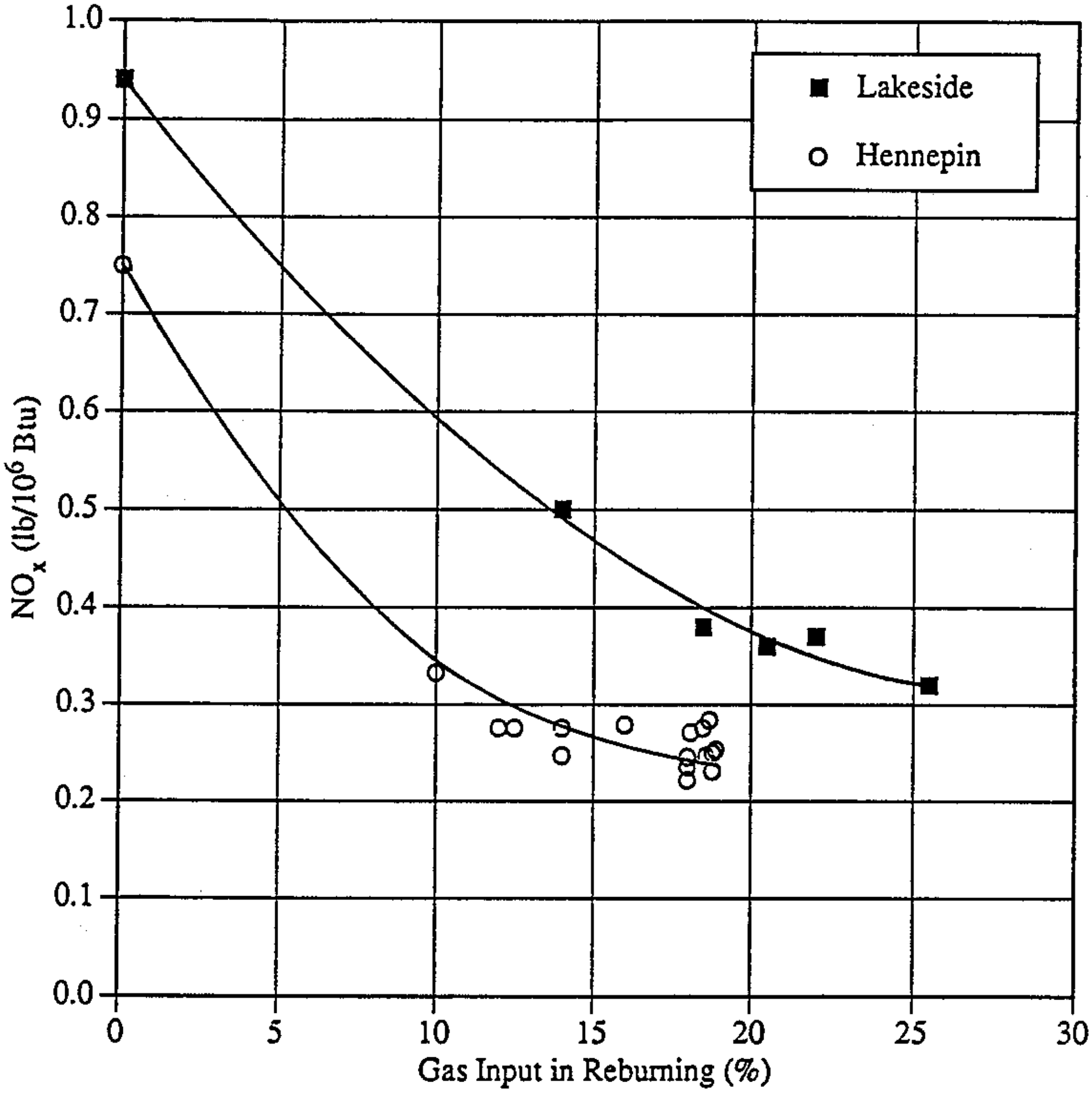


Figure 2



Fgure 3. NOx vs Gas Heat Input

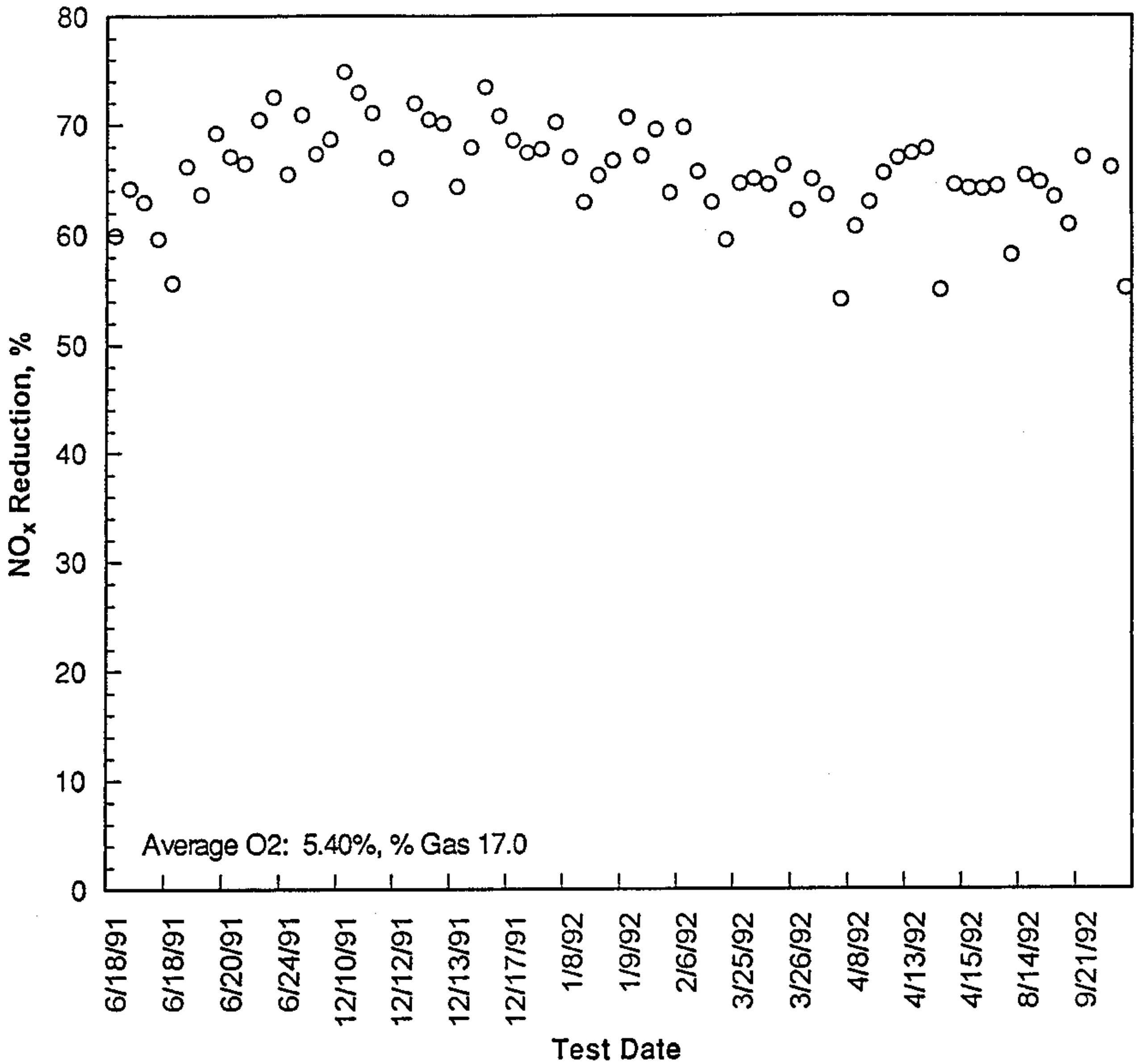


Figure 4. IP NOx Reduction vs time

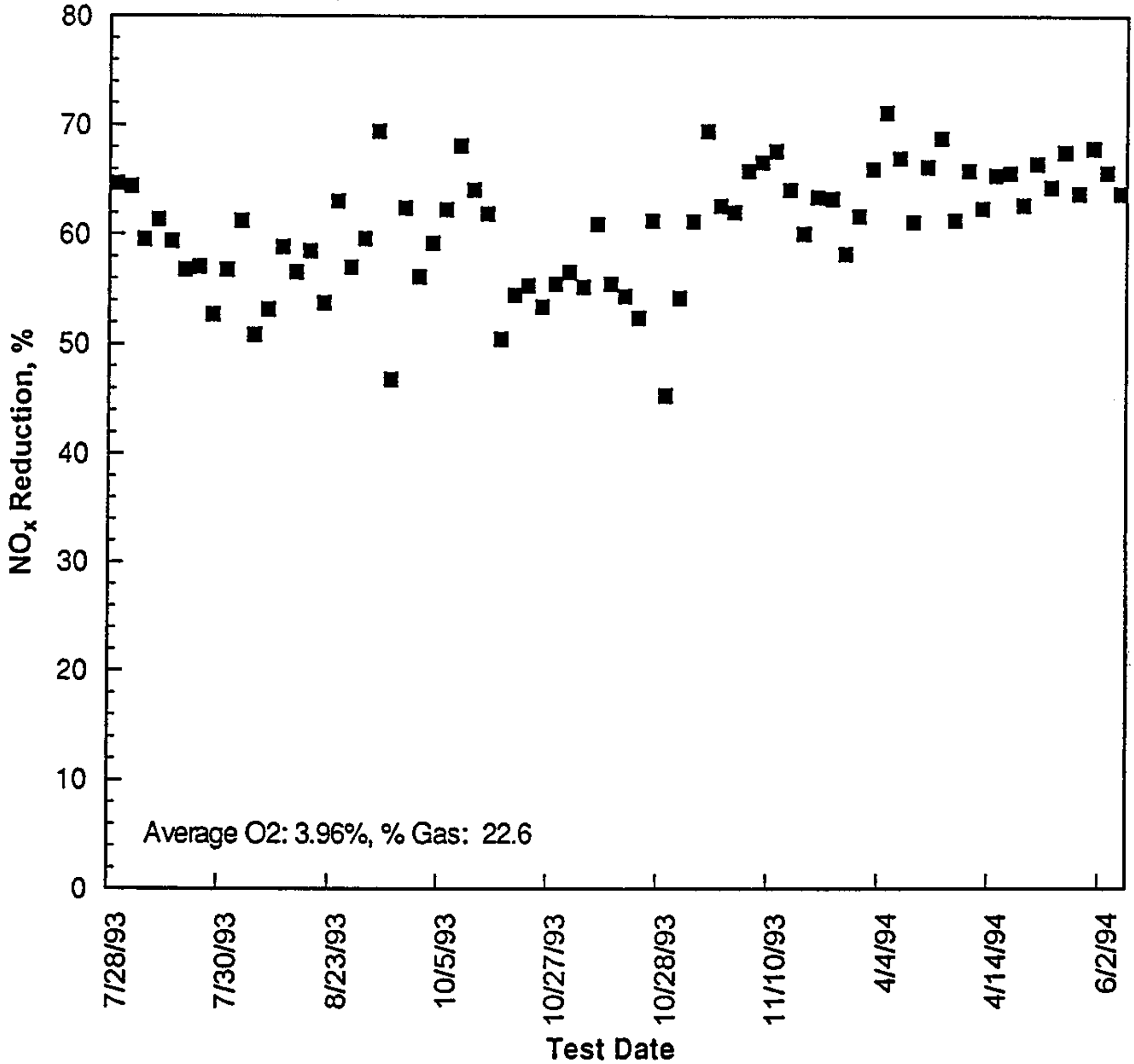


Figure 5. CWLP NOx Reduction vs time

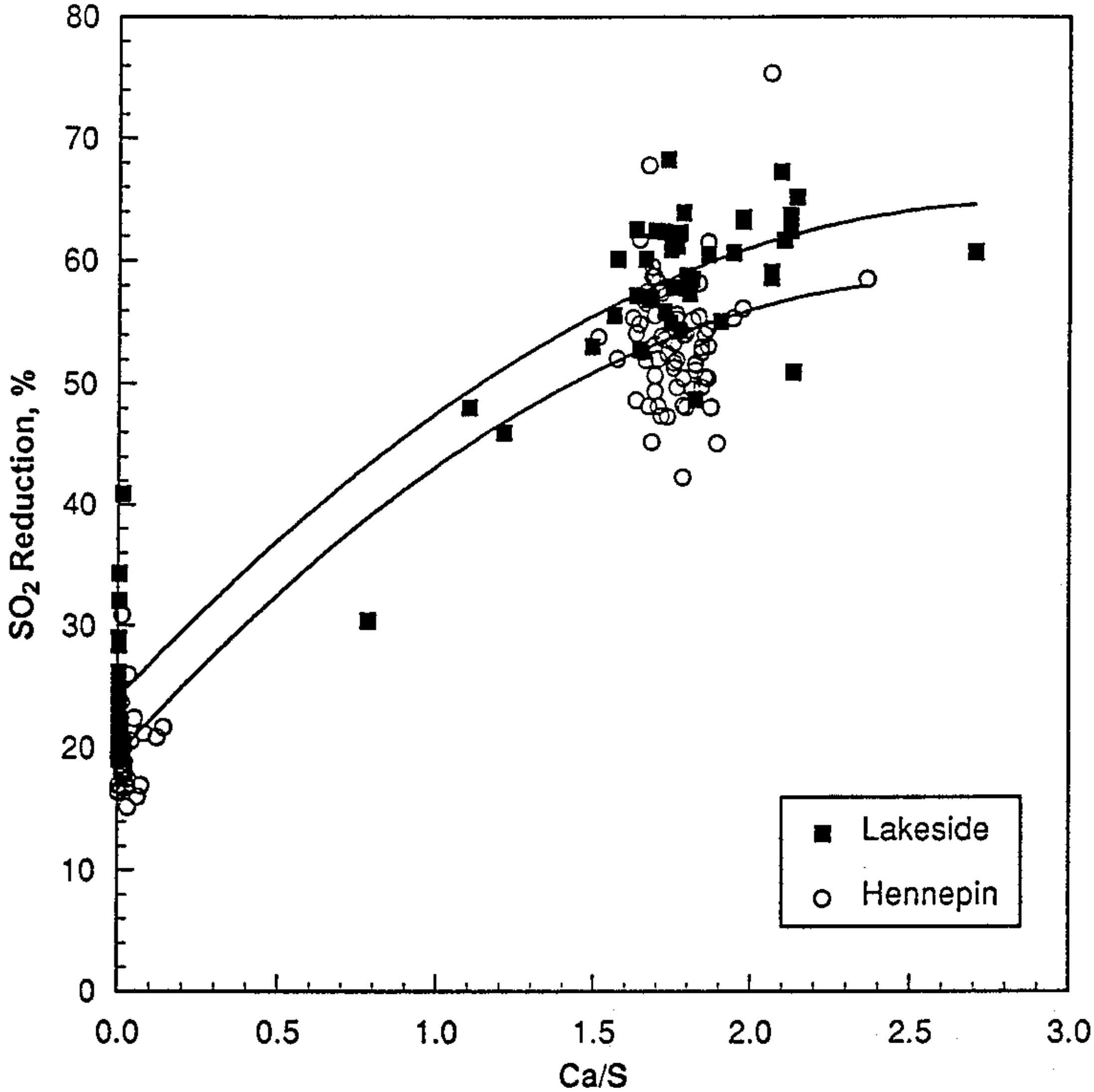


Figure 6. SO2 Reduction vs Ca/S

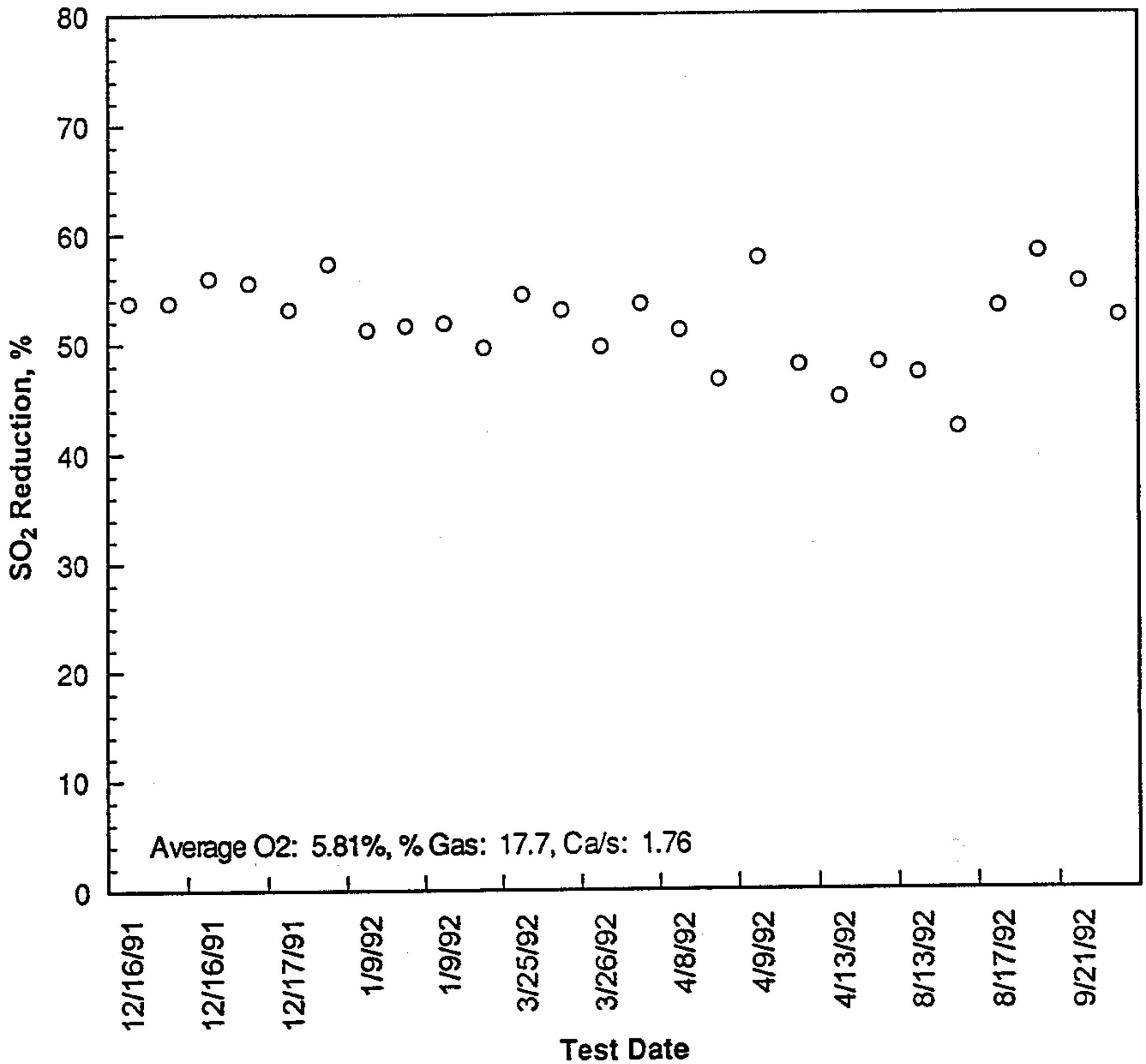


Figure 7. IP SO2 Reduction vs time

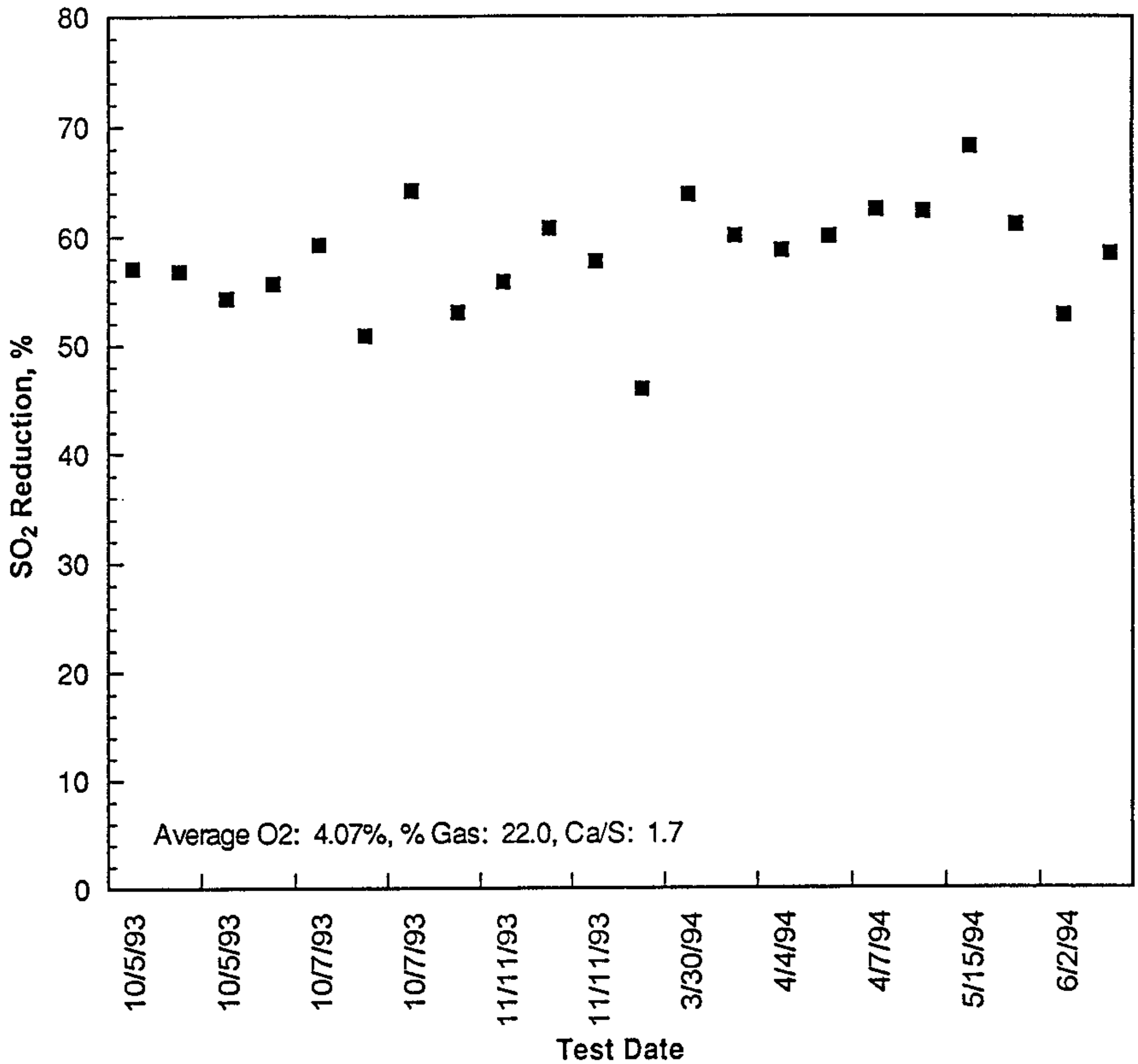


Figure 8. CWLP SO2 Reduction vs time

DEMONSTRATION OF GAS REBURNING-LOW NO_x BURNER TECHNOLOGY FOR COST EFFECTIVE NO_x EMISSION CONTROL

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ABSTRACT

Under the DOE Clean Coal Technology Program, EER successfully applied gas reburning and low NO_x burner (GR-LNB) technology to a 172 MWe wall-fired utility boiler. NO_x emission reductions exceeding the program goals were demonstrated with no significant detrimental impacts on the boiler operation. All testing and evaluation has been completed and the host utilities has elected to purchase the GR-LNB equipment for future use.

This paper presents the results of the long-term evaluation of the GR-LNB technology. In addition, an economic comparison with competing NOx control technologies will be presented along with plans for commercial deployment.

INTRODUCTION

As part of the U.S. Department of Energy's Clean Coal Technology Program (Round 3), a project was completed to demonstrate control of boiler emissions that comprise acid rain precursors, specifically NO_x. The project involved operating combined gas reburning and low NO_x burners (GR-LNB) on a coal-fired utility boiler to determine the reductions in this boiler emission. Low NO_x burners are designed to create less NO_x than conventional burners. However, the NO_x control achieved is limited to 30-50%. Also, CO emissions tend to be at levels above acceptable standards. Gas reburning (GR) is designed to reduce the level of NO_x in the flue gas by staged fuel combustion. This technology involves the introduction of natural gas into the flue gas stream. When combined, gas reburning and low NO_x burners work in harmony to both minimize NO_x emissions and maintain an acceptable level of CO emissions. Several additional benefits are also derived from adding gas reburning to LNB including:

- Low capital cost relative to more expensive scrubbers
- Compatibility with high-sulfur coal
- Incremental reduction in SO_2 emissions, since natural gas contains no sulfur.
- No adverse effects on boiler thermal performance
- Minimal system operating complexity

The demonstration was performed at Public Service Company of Colorado's (PSCo) Cherokee Unit 3, located in Denver, Colorado. This unit is a 172 MWe wall-fired boiler that uses Colorado bituminous, low-sulfur coal. The target for the project was a reduction of 70 percent in NO_x emissions.

TECHNOLOGY DESCRIPTION

Gas reburning involves reducing the levels of coal and combustion air in the burner area and injecting natural gas above the burners followed by the injection of overfire air (OFA) above the reburning zone as shown in Figure 1. This three-zone process creates a reducing area in the boiler furnace within which NO_x created in the primary zone is reduced to elemental nitrogen and other less harmful nitrogen species. Each zone has a unique stoichiometric ratio (ratio of air to that theoretically required for complete combustion) as determined by the flow of coal, burner air, natural gas, and OFA. Flue gas recirculation (FGR) may be used to provide momentum to the natural gas injection. Although FGR has a low O_2 content, it also has a minor impact on reburning and burnout zone stoichiometries. The descriptions of the zones are as follows:

- Primary (burner) Zone: Coal is fired at a rate corresponding to 75 to 90 percent of the total heat input, under low excess air. NO_x created in this zone is limited by the lower heat release and the reduced excess air level.

- Reburning Zone: Reburning fuel (natural gas in this case) injection creates a fuel rich region within which methane breaks down to hydrocarbon fragments (CH, CH_2, etc.) which react with NO_x, reducing it to atmospheric nitrogen. The optimum reburning zone stoichiometry is 0.90, achieved by injecting natural gas at a rate corresponding to 10 to 25 percent of the total heat input.

- Burnout (exit) Zone: Overfire air is injected higher up in the furnace to complete the combustion. OFA is typically 20 percent of the total air flow; a minimum excess air of 15 percent in maintained. OFA injection is optimized to minimize CO emissions and unburned carbon-in-fly ash.

Ambient air is used to cool the gas injection nozzles when the gas reburning system is not in operation. The GR-LNB system is controlled by a Westinghouse Distributed Process Family system (WDPF). The WDPF provides integrated modulating control, sequential control and data acquisition for a wide variety of system applications. All start/modulation/stop operations are performed in the control room using a keyboard-CRT with custom graphics. The control system was designed to accommodate operation of the boiler with or without gas reburning.

Gas reburning and low NO_x burners are applied simultaneously to maximize the reduction in NO_x emissions. CO levels, traditionally a problem with low NO_x burners, are controlled with overfire air.

Second Generation Gas Reburning

Flue gas recirculation was used initially to provide momentum to the natural gas in order to achieve optimum boiler penetration. However, during the long term testing phase of the project, it was determined that the flue gas recirculation had minimal effect on NO_x emissions. Therefore, a second series of tests was added to the project to evaluate the modified configuration and gage its impact. The modification details are as follows:

- The flue gas recirculation system, originally designed to provide momentum to the natural gas, was removed. The change will result in reduced capital costs on future designs.

- Natural gas injection was optimized at 10% gas heat input, compared to the First Generation operating value of 18%. FGR elimination required incorporation of high velocity injectors, which made greater use of the available natural gas pressure. The change resulted in reduced operating cost due to the lower gas usage.

- Overfire air ports were modified to provide higher jet momentum, especially at low total flows.

- The overfire air ports were modified to provide air swirl capability and velocity control. The modification was designed to improve lateral coverage of the furnace and turbulence in mixing with unburned fuel. This change provided CO control at the lower gas levels, which was a concern with the First Generation design.

HISTORICAL PERSPECTIVE

The development of gas reburning technology has been underway in various laboratories since the 1970's. EER, with the support of the EPA and GRI, began extensive bench and pilot-scale testing in 1981 to characterize the fundamental process variables. These tests provided valuable scale-up information needed for the development of commercial applications under industrial conditions.

EER's Gas Reburning-Low NO_x Burner project at PSCo was part of the U.S. Department of Energy's Clean Coal Technology Round 3 Program. The goal of the project was to demonstrate that combined GR-LNB could be successfully incorporated into a wall-fired boiler to achieve significant reductions in NO_x emissions. The total value of the project was $17.8 million. Awarded in October of 1990, the project will be successfully completed at the end of 1995.

Project Schedule and Status

The project was divided into the following three phases:

- Phase I — Design and Permitting
- Phase II — Construction and Startup
- Phase III — Operation, Data Collection, Reporting and Disposition

The schedule for the project is shown in Figure 2. Both first and second generation testing have been completed and the final report is in progress. Based on the successful results of the second generation testing, the flue gas recirculation system will be removed from the boiler. The remainder of the gas reburning system will be retained by PSCo.

Process Design

The process design was performed during Phase I of the Project. The goal in the design of the GR-LNB system was to achieve the emissions control objectives while minimizing impacts on other areas of unit performance. Using NO_x reduction reaction modeling and isothermal physical flow modeling, the process stream inputs and injection details of the GR-LNB system were finalized. Heat transfer modeling was then conducted to predict the impacts on heat absorptions by each heat exchanger and steam side and gas side temperatures. Also evaluated were the potential effects on various areas of boiler performance including fuel burnout, furnace slagging, and waterwall wastage. As a result of the process design effort, the following parameters were established:

- Natural gas and overfire air injector sizes, required numbers, and boiler locations.
- Volume flow rates for natural gas, flue gas recirculation, and overfire air.
- Flue gas recirculation and overfire air fan specifications.
- Initial operating set-points for optimum boiler stoichiometries.

Installation and Integration

The GR-LNB system was installed during Phase II of the Project. The existing sixteen burners were replaced by Foster-Wheeler internal fuel-staging low NO_x burners. The burners employ dual combustion air registers which allow for control of air distribution at the burner, providing independent control of the ignition zone and flame shape. A NO_x emission reduction of 45% from baseline was anticipated at full load conditions.

The gas reburning system retrofit involved routing natural gas to the sixteen boiler penetrations (8 front and 8 rear), installing a flue gas recirculation fan, installing a multiclone dust collector to remove particulate and protect the fan, and connecting the equipment with ductwork. The overfire air system involved installing an overfire air fan and installation of ductwork from the secondary air system to the six front-wall injection nozzles. An extensive plant outage was required to install boiler penetrations. Some outage time was also required to modify the control system.

Test Plan and Testing

Phase III of the Project was devoted to demonstration of the technology. Following startup and optimization of the low NO_x burners, a series of pre-planned parametric tests were performed on the gas reburning system. These tests were conducted at different boiler load conditions and involved varying operational control parameters (such as boiler zone stoichiometries, natural gas heat input, flue gas recirculation flow rate, overfire air flow rate, etc.) and assessing the effect on boiler emissions, completeness of combustion (carbon-in-ash), thermal efficiency, and heat rate. The baseline condition of the low NO_x burners was also established.

A one-year duration long term testing program was performed in order to judge the consistency of system outputs, assess the impact of long-term operation on the boiler equipment, gain experience in operating GR-LNB in a normal load-following environment, and develop a database for use in subsequent GR-LNB applications. Both first and second generation gas reburning testing were performed.

TEST RESULTS

Emissions

EER conducted a comprehensive test demonstration program, operating the equipment over a wide range of boiler conditions. Over 4,000 hours of operation were achieved enabling EER to obtain a substantial amount of data. Intensive measurements were taken to quantify the reductions in NO_x emissions, the impact on boiler equipment and operability, and all factors influencing costs. The results showed that GR-LNB technology achieved excellent emissions reductions and all goals of the project were achieved. The following table summarizes the results of the combined gas reburning-sorbent injection operation:

	First Generation	Second Generation
NO_x emissions		
baseline	.73 lb/MMBtu	.73 lb/MMBtu
average reduction (LNB)	37%	37%
average reduction (GR-LNB)	65%	64%
average gas heat input	18%	13%

The results are presented in detail on Figures 3 thru 6. Figure 3 presents the relationship between NO_x emissions and percent of gas heat input. The data shows that NO_x decreased as the reburning gas heat input increased. Also, as shown in Figure 4, the performance goal (reduction of NO_x emissions by 70%) was met on most test runs. The performance of the low NO_x burners was somewhat less than expected. The average NO_x reduction of 37% was below the expected 45%. Also, longer flames persisted into the upper furnace region, and the carbon-in-ash and CO were above acceptable levels. These problems impacted the gas reburning NO_x performance. Although, modifications and re-tuning were performed on the burners prior to Second Generation testing, overall burner performance did not improve.

Figure 6 presents the relationship between CO emissions and percent of gas heat input. For First Generation Gas Reburning, lower CO values occurred when gas heat input was between 10 and 15 percent. However, During Second Generation Gas Reburning, following modifications performed on the overfire air nozzles to improve boiler penetration at low flow, CO was found to be controllable at much lower gas heat inputs. Thus, the NO_x and CO benefits of the Second Generation system were in fact achieved with low levels of gas, as anticipated.

Title IV, Phase 1 of the Clean Air Act Amendments of 1990 specify a NO_x emissions limit of 0.50 lb/MMBtu for wall-fired boilers. It is expected that this limit will be lowered in the future. The results of this test show that burners alone will produce a NO_x emission of .46 lb/MMBtu. Although sufficient to meet the limit, the CO control is not achieved unless a small amount of gas reburning is utilized. Also, any future limit will not be met with burners alone; an additional control feature will be required. For this unit, it was demonstrated that gas reburning is the optimal control feature due to its low capital cost outlay and low operating cost (with small levels of gas).

Boiler Impacts

Although boiler stoichiometries were altered as an inherent requirement of gas reburning, no adverse effects on either boiler efficiency or equipment were observed. Also, no abnormal control room procedures were required when the system was in operation.

During gas reburning there was minimal impact on the boiler heat absorption profile. Subsequently, steam temperatures also showed minimal variation. However, gas reburning resulted in higher flue gas temperatures in the superheater region, the effect of which was controlled by an increase in steam attemperation.

The boiler efficiency decreased by approximately 1% during gas reburning due moisture in the fuel and an increase in heat loss due to moisture formed in combustion. Note that a higher flue gas moisture content results from firing natural gas which has a higher hydrogen-to-carbon ratio than coal.

The boiler tubes were examined for tube wear and slagging. Based on several ultrasonic tube thickness measurements conducted during the test program, it was concluded that there was no measurable wear resulting from GR-LNB operation. In general, the boiler tubes were free from slagging. The small amounts of slagging that did exist were attributed to the burners and not gas reburning.

COMMERCIAL APPLICATIONS

The gas reburning-low NO_x burner project has demonstrated the success of GR in reducing NO_x emissions. Utilizing the process design conducted early in the project with the vast amount of data collected during the testing, EER has developed a database of information necessary to apply the technologies to both utility and industrial units. The emissions control and performance can be accurately projected as can the capital and operating costs. GR-LNB technology has now been developed to the point that it can be offered by EER on commercial terms.

Economic Considerations

Economics are a key issue affecting technology development. Application of GR-LNB requires modifications to existing power plant equipment. As a result, the capital costs and operating costs depend largely on site-specific factors such as:

- Gas availability at the site
- Coal-gas cost differential
- Sulfur dioxide removal requirements
- Value of SO_2 allowances

Based on the results of this project, EER expects that most GR-LNB installations will achieve at least 60% NO_x control when firing 10-15% gas. The capital cost estimate for installing a gas reburning system on units of 100 MW and larger is in the range of $15/kw plus the cost of a gas pipeline (if required). Operating costs are almost entirely related to the differential cost of the gas over the coal as reduced by the value of SO_2 emissions reduction (due to the zero sulfur content of natural gas). Other operating cost factors are related to reductions in ash, mill power and maintenance, and a minor reduction in boiler efficiency, typically 0.0 to 1.0%.

SUMMARY

The following results can be highlighted from the Gas Reburning-Low NO_x Burner demonstration:

- GR-LNB can be installed and operated successfully on wall-fired boilers
- The project goal of 70% NO_x reduction was achieved.
- The system was operated consistently and reliably
- The system demonstrated no significant thermal impact
- CO can be controlled by exit stoichiometry
- Existing boiler equipment experienced no mechanical degradation or failure
- Second Generation Gas Reburning produced acceptable results at low levels of gas heat input.

ACKNOWLEDGMENTS

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- U.S. Department of Energy
- Gas Research Institute
- Public Service Company of Colorado
- Colorado Interstate Gas
- Electric Power Research Institute
- Energy and Environmental Research Corporation

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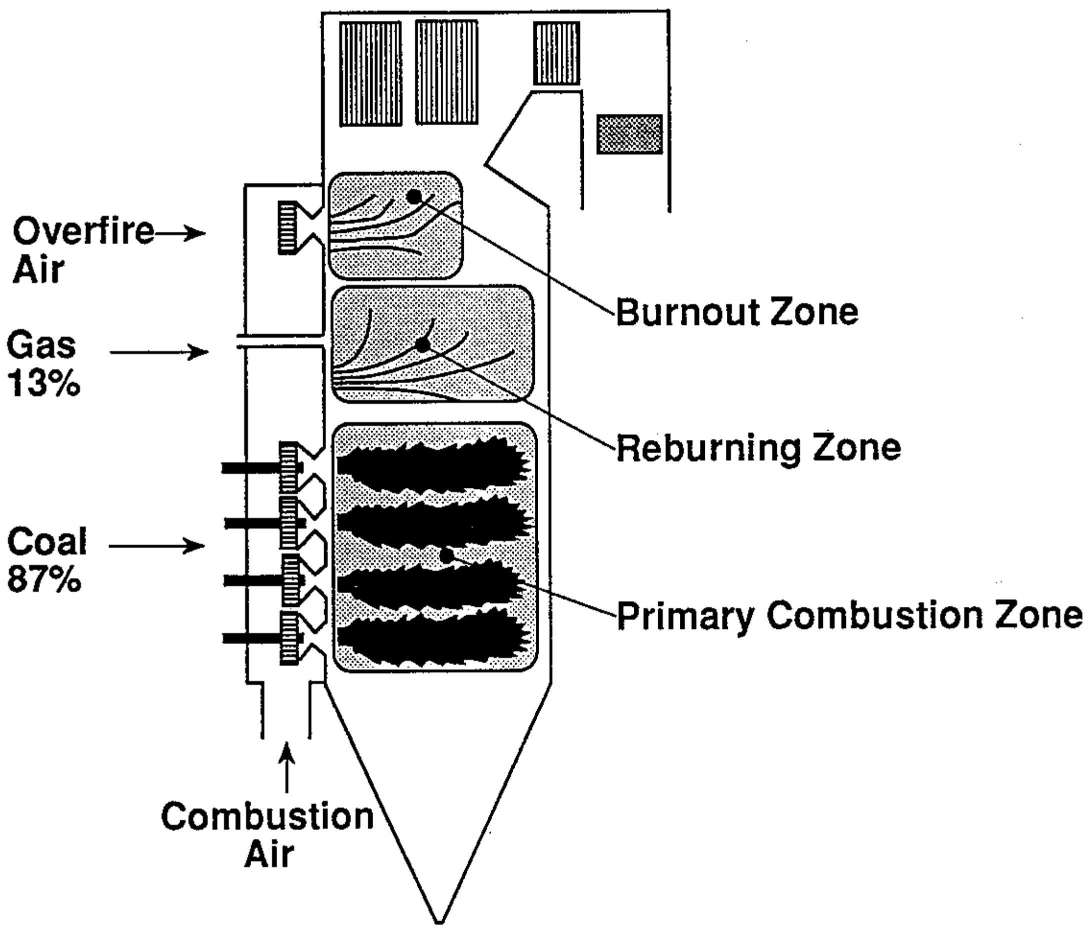

Figure 1. Schematic of Gas Reburning System

Demonstration of Gas Reburning-Low NOx Burner Technology
Project Schedule

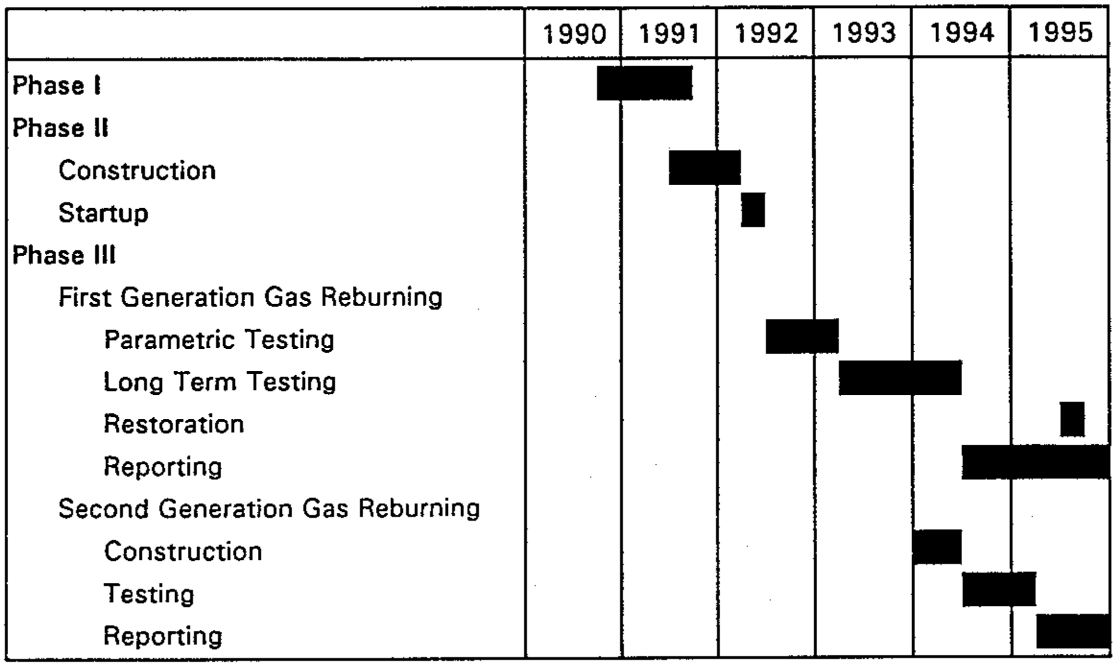

Figure 2

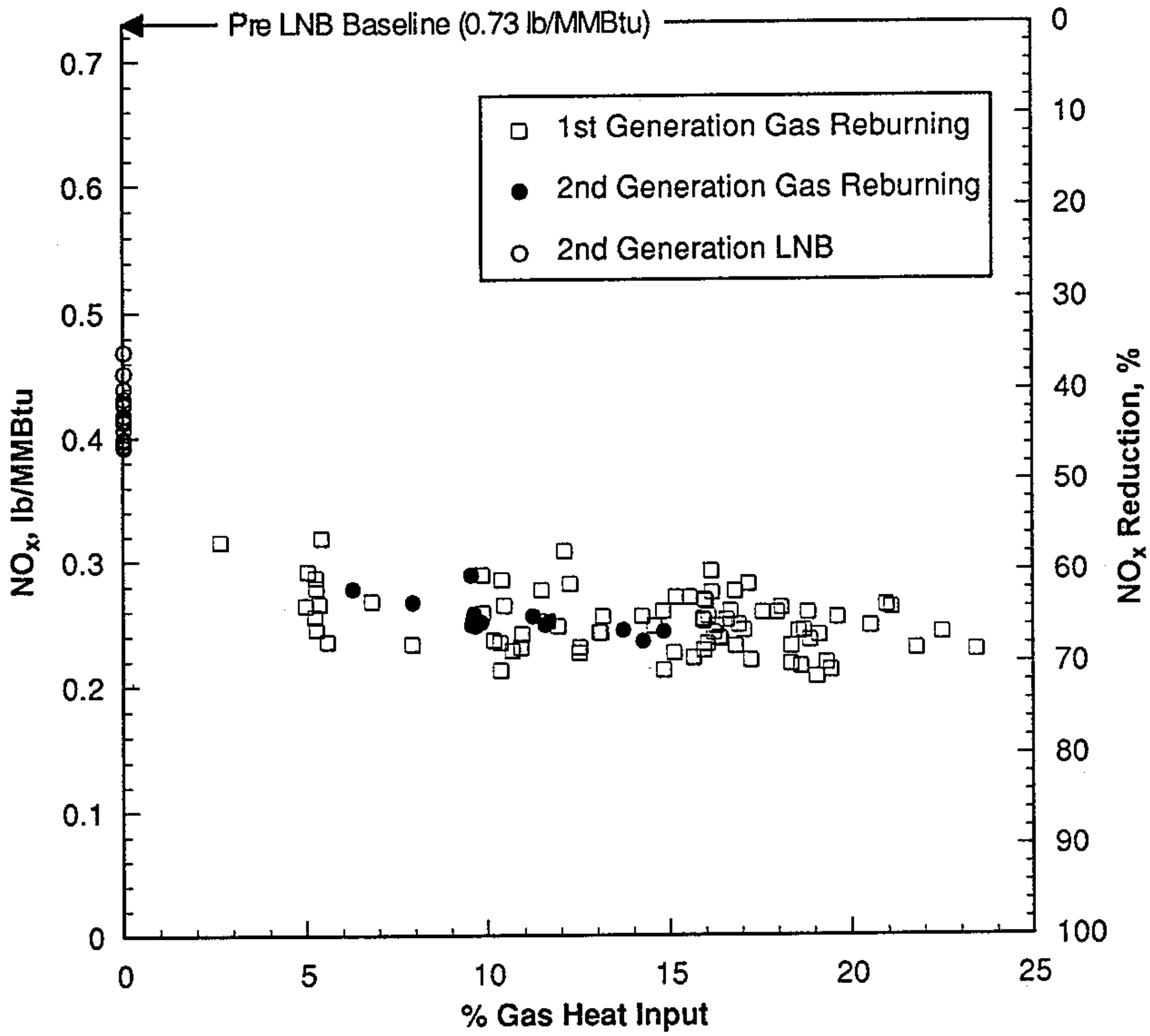

Figure 3. NOx vs. Gas Heat Input

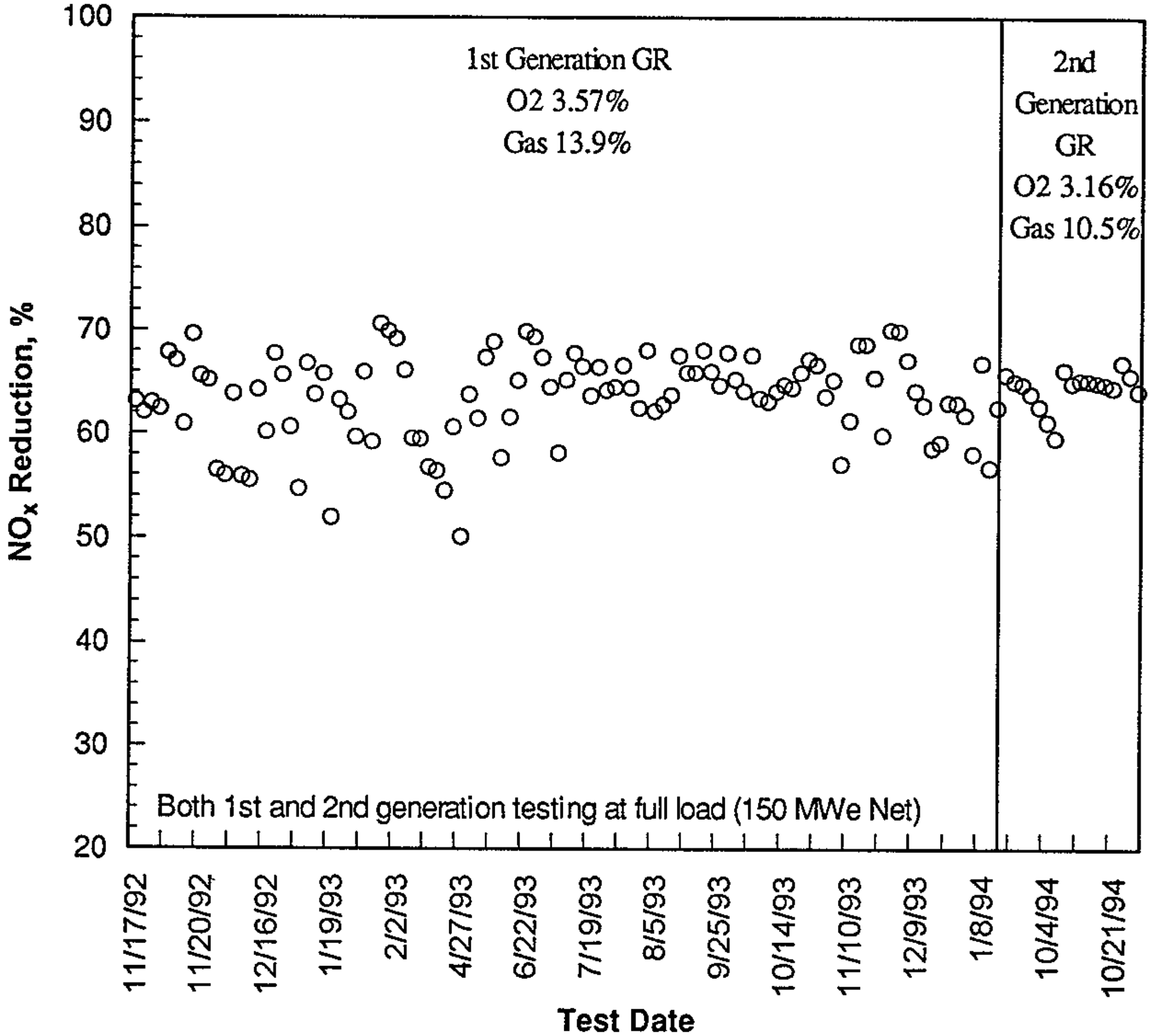

Figure 4. NOx Reduction vs. Time

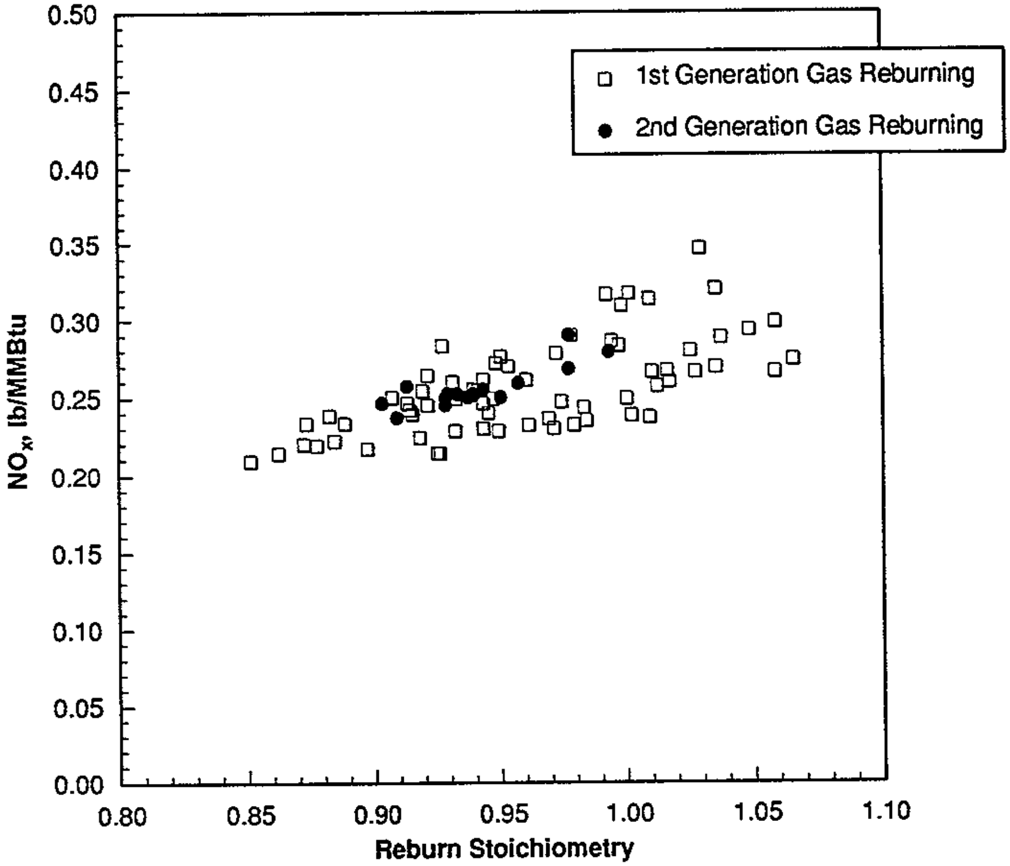

Figure 5. NOx vs. Reburning Zone Stoichiometry

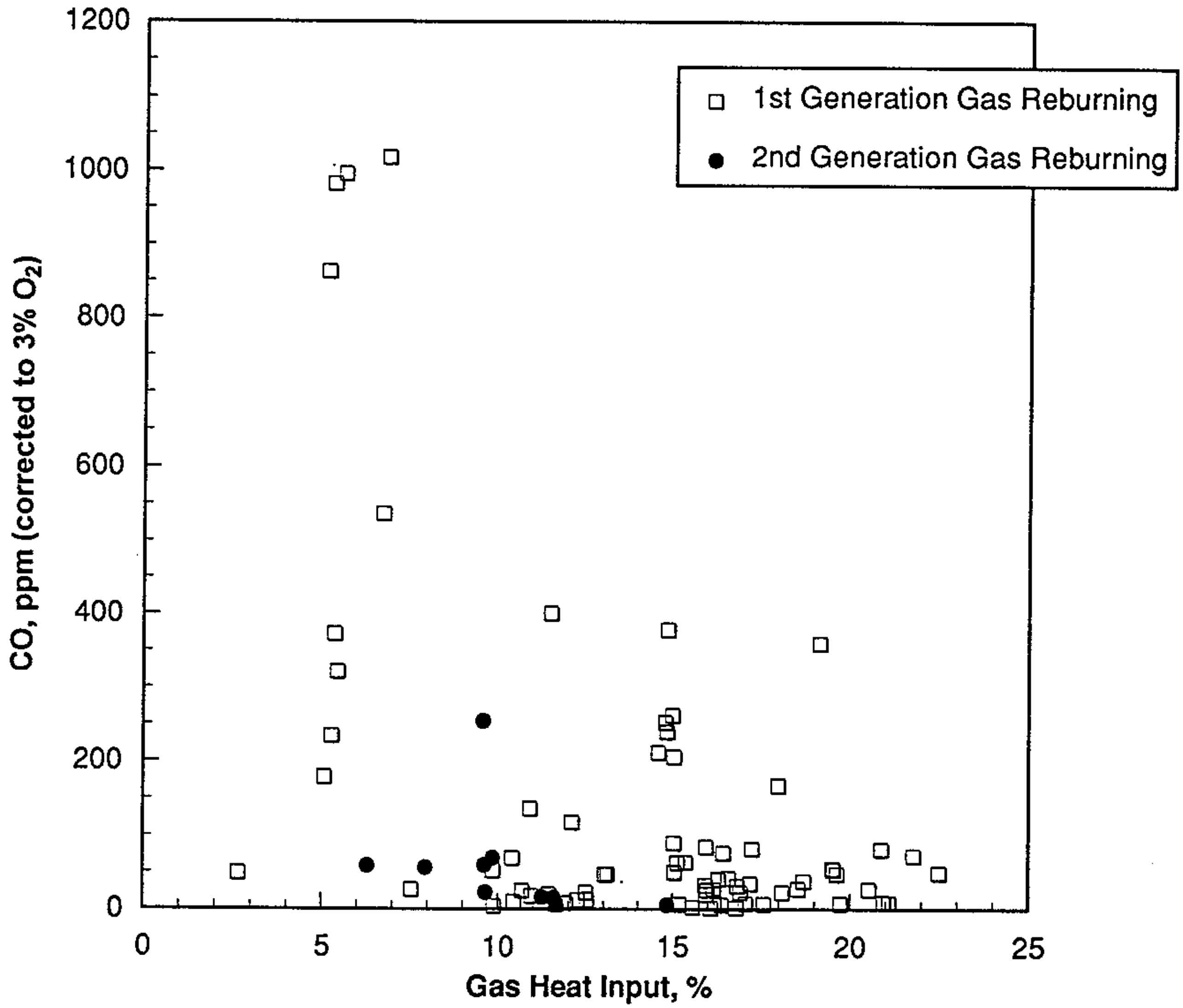

Figure 6. CO vs Gas Heat Input

DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY FOR THE CONTROL OF NITROGEN OXIDES (NOx) EMISSIONS FROM HIGH SULFUR COAL-FIRED UTILITY BOILERS AT PLANT CRIST SCR TEST FACILITY

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ABSTRACT

This paper describes the status of the Innovative Clean Coal Technology project to demonstrate SCR technology for reduction of NOx emissions from flue gas of utility boilers burning U.S. high-sulfur coal. The project is sponsored by the U.S. Department of Energy, managed and co-funded by Southern Company Services, Inc. on behalf of the Southern Company, and also co-funded by the Electric Power Research Institute and Ontario Hydro; and is located at Gulf Power Company's Plant Crist Unit 5 (75 MW tangentially-fired boiler burning U.S. coals that have a sulfur content near 3.0%), near Pensacola, Florida. The test program is being conducted for approximately two years to evaluate catalyst deactivation and other SCR operational effects. The SCR test facility has nine reactors: three 2.5 MW (5000 scfm), and six 0.2 MW (400 scfm). Eight reactors operate on high-dust flue gas, while the ninth reactor operates on low-dust flue gas using a slip stream at the exit of the host unit's hot side precipitator. The reactors operate in parallel with commercially available SCR catalysts obtained from vendors throughout the world. Long-term performance testing began in July 1993. A general test facility description and the results from three parametric test sequences and long term test data through December 1994 are presented in this paper.

INTRODUCTION

Selective catalytic reduction (SCR) is a process in which ammonia is added to the flue gas to reduce NOx to nitrogen and water over a catalyst. The need within the utility industry for detailed information on SCR technology has never been greater. The 1990 U.S. Clean Air Act

Amendments (CAAA) create two new nitrogen oxide (NOx) control requirements on fossil fuel-fired utility boilers. First, Title IV of the CAAA regarding acid rain addresses NOx emission limits on all coal-fired utility boilers. Second, Title I of the CAAA (attainment of the ambient air quality standards) calls for certain areas presently not in attainment on ozone to consider NOx controls to achieve attainment. As a result, renewed focus has been placed on advanced NOx control technologies such as SCR, which may be required to meet compliance requirements associated with the CAAA.

SCR technology is in commercial use in Japan and Western Europe on gas-, oil-, and low-sulfur coal-fired power plants. There are now over 36,000 MW of fossil-fuel-fired SCR capacity in Japan, including 6,200 MW on coal. There are over 33,000 MW of fossil-fuel-fired SCR capacity in Western Europe, including 30,500 MW of coal-fired capacity.[1]

SCR DEMONSTRATION GOALS

Although SCR is widely applied in Japan and Western Europe, numerous technical uncertainties are associated with applying SCR to U.S. coals. These uncertainties include:

* potential catalyst deactivation due to poisoning by trace metal species present in U.S. coals but not present, or present at much lower concentrations, in fuels from other countries;

* performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO_2 and SO_3 (e.g., plugging of downstream equipment with ammonia-sulfur compounds); and

* performance of a wide variety of SCR catalyst compositions, geometries and manufacturing methods at typical U.S. high-sulfur coal-fired utility operating conditions.

These uncertainties are being explored by constructing and operating a series of small-scale SCR reactors and simultaneously exposing different commercially available SCR catalysts to flue gas derived from the combustion of high-sulfur U.S. coal. First, SCR catalyst performance is being evaluated for two years under realistic operating conditions found in U.S. pulverized-coal-fired utility boilers. Deactivation rates for the catalysts exposed to flue gas of high-sulfur U.S. coal are being documented to determine catalyst life and associated process economics. Second, parametric tests are being performed during which SCR operating conditions are being adjusted above and below design values to observe deNOx performance and ammonia slip. The performance of air preheaters installed downstream of the larger SCR reactors will also be observed to evaluate the effects of SCR operating conditions on heat transfer and boiler efficiency. Third, Honeycomb- and plate-type SCR catalysts of various commercial compositions from the U.S., Japan, and Europe are being evaluated. Tests with these catalysts will expand knowledge of the performance of SCR catalysts under U.S. utility operating conditions with high-sulfur coal.

The intent of this project is to demonstrate commercial catalyst performance and to determine optimum operating conditions and catalyst life for the SCR process. This project will also demonstrate the technical and economic viability of SCR while reducing NOx emissions by at least 80% and maintaining acceptable ammonia slip (5 ppm).

SCR TEST FACILITY DESCRIPTION

The SCR demonstration facility is located at Gulf Power Company's Plant Crist in Pensacola, Florida. The facility treats a flue gas slip-stream from Unit 5, a commercially operating 75-MW unit, firing U.S. coals with a sulfur content near 3.0%. Unit 5 is a tangentially-fired, dry bottom boiler with hot- and cold-side electrostatic precipitators (ESPs) for particulate control. The SCR test facility consists of nine reactors operating in parallel for side-by-side comparisons of commercially available SCR catalysts obtained from vendors throughout the world. With all reactors in operation, the amount of combustion flue gas that can be treated is 17,400 scfm or 12% of Unit 5's capacity (about 8.7 MWe). Table 1 shows typical pilot facility flue gas constituent concentrations and particulate loadings.

The process flow diagram for the SCR test facility is shown in Figure 1. There are three large SCR reactors (2.5 MW, 5000 scfm) and six smaller SCR reactors (0.2 MW, 400 scfm). Eight of the nine reactors operate with flue gas containing full particulate loading (high dust) extracted from the inlet duct of the hot-side ESP, while one small reactor uses flue gas fed from the ESP outlet (low dust). Only eight reactors are now being operated, one high-dust small reactor is idle.

Each reactor train has electric duct heaters to control the temperature of the flue gas entering the reactor and a venturi flow meter to measure the flue gas flow. An economizer bypass line to the SCR test facility maintains a minimum temperature of 620 °F for flue gas supplied to the test facility. Anhydrous ammonia is independently metered to a stream of heated dilution air that injects the ammonia via nozzles into the flue gas stream upstream of each SCR reactor. The flue gas and ammonia pass through the SCR reactors, which have the capacity to contain up to four catalyst layers.

For the large reactor trains, the flue gas exits the reactor and enters a pilot-scale air preheater (APH). The APHs are incorporated in the project to evaluate the effects of SCR reaction chemistry on APH deposit formation and the effects of the deposits on APH performance and operations. All reactor trains, except the low-dust train, have a cyclone downstream of the SCR reactor to protect the induced draft (ID) fans from particulates. The exhaust for all the SCR reactors is combined into a single manifold and reinjected into the host boiler's flue gas stream ahead of the cold-side ESP. The preheated air from the APH on the large reactors is also combined into a single manifold and returned to the host boiler draft system at the air outlet of the existing APH. All of the particulate that is removed from the flue gas with the cyclones is combined and sent to an ash disposal area.

AIR PREHEATER TESTING PLANS

Air preheater tests include a number of performance measurements aimed at determining the effects of SCR installations on downstream air preheaters. These tests include pressure drop tracking, sootblowing efficiency tests, general heat transfer analysis, washing efficiency and requirements, corrosion analyses, and basket weight loss. By nature, these air preheater tests are long-term. Included in the project final report will be details of expected washing requirements, sootblowing requirements and basket replacement requirements for the operation of air preheaters in conjunction with SCR installations.

CATALYST TESTING PLANS

Six catalyst suppliers are participating in this project, providing eight different catalysts. The suppliers, corresponding reactor size, and catalyst configuration are listed in Table 2. The two suppliers from Europe and two from Japan provide one catalyst each. The two U.S. firms are supplying four of the catalysts. The catalysts being evaluated represent the wide variety of SCR catalysts being offered commercially and possess different chemical compositions and physical shapes. Of these eight catalysts, five have a honeycomb geometry while the remaining three are plate-type catalysts.

After start-up, the baseline performance of each catalyst was determined at design conditions which are being maintained for the two year test period. Once baseline performance was established, each reactor was sequenced through a series of parametric tests that varied the following variables around the SCR process baseline point: NH_3/NOx ratio, temperature, and space velocity. Space velocity is the ratio of flue gas volumetric flow rate to catalyst volume. With a fixed catalyst volume, variations in flue gas flow rates alter the space velocity around the design point.

DeNOx efficiency, pressure drop, SO_2 oxidation, and ammonia slip are determined at specific parametric test conditions. After each parametric test matrix has been completed, each reactor is returned to baseline conditions. This allows for steady-state operation to age the catalyst between parametric tests. The parametric test matrix is repeated every four months for each reactor train. The operating parameter ranges examined during the parametric tests and the long-term design conditions (baseline) are as follows:

	Minimum	Baseline	Maximum
Temperature, (°F)	620	700	750
NH_3/NOx molar ratio	0.6	0.8	1.0
Space velocity, (% of design flow)	60	100	150
Flow rate, (scfm)			
-large reactor	3000	5000	7500
-small reactor	240	400	600

PROJECT SCHEDULE AND STATUS

The demonstration project was organized into three phases. Phase I consisted of permitting, preparation of the Environmental Monitoring Plan, and preliminary engineering. Phase II included detailed design engineering, construction, and start-up/shakedown. Detailed design engineering began in early 1991 and concluded in December, 1992. Construction began at the end of March 1992 and was completed by the end of February 1993. Start-up/shakedown concluded in June 1993. Baseline commissioning tests without catalysts were conducted through June. The loading of all catalysts was completed at the end of June.

The operational phase for process evaluation, Phase III, commenced in July 1993. The process evaluation will last for approximately two years and will be followed by preparation of a final report, which will include catalyst technical performance and process economic projections. The major milestones on the schedule are shown in Table 3.

PARAMETRIC AND LONG TERM TEST RESULTS

The parametric and long term catalyst testing can be divided into four main categories: 1) test facility ammonia measurements, 2) test facility sulfur trioxide measurements, 3) test facility general reactor performance measurements, and 4) catalyst supplier laboratory tests. The ammonia measurements consist of measurements of intermediate ammonia (usually downstream of the first catalyst bed), and slip ammonia measurements (at the reactor exit). These ammonia measurements are used to assess the deNOx performance of the catalyst. Sulfur trioxide measurements are performed at the inlet and outlet of the reactor to determine the SO_2 oxidation characteristics of the catalyst. Other parameters are also measured to determine reactor performance. These parameters include NH_3/NOx distributions at the reactor inlet, particulate and velocity distributions within the reactor, and pressure drops across the catalyst beds. Also included in the parametric testing are measures of HCl and N_2O concentrations at the inlets and outlets of the reactors.

The catalyst suppliers were given a great deal of latitude in selecting the type and amount of catalyst that each provided for the test facility. For this reason, various parameters such as pressure drop, total surface area, and space velocity differ significantly between the catalysts installed in the pilot plant. Direct comparisons of catalyst performance should not be made from the presented date. Rather, the information should be used to evaluate each particular catalysts' performance in terms of changes in operating parameters and the catalyst performance as a function of exposure time. Direct comparisons of catalyst performance must include economic analyses which will be performed for the final project report.

AMMONIA MEASUREMENTS

Of particular concern in SCR operation is the relative decline of deNOx activity over time. This decline is often indicated in the field by increasing ammonia slip exiting the reactor over time. Figure 2 shows the measured ammonia slip for each catalyst as a function of time exposed to flue gas. The data show a slight upward trend in ammonia slip for the 7,000 hour operational period. In most cases however, this upward trend represents less than 1 ppm increase in ammonia slip. Some uncertainty exists in the exact evaluation of ammonia slip, since most measurements are near the ammonia detection limit and measurement accuracy is relatively poor (± 0.3 ppm) at these very low ammonia concentrations. In addition, the plot assumes that the NH_3/NOx ratio is constant. In reality, slight variation exist in the NH_3/NOx ratio which contribute to the scatter of the data. This is especially true of early slip measurements where the NH_3/NOx ratio was consistently high due to calibration errors. The most important conclusion to be drawn from the figure is that ammonia slip has not significantly increased over the 7,000 hour operational period.

In addition to the evaluation of baseline slip over time, other important characteristics such as the catalyst response to changes in flow rate (space velocity) and temperature are also examined using intermediate and ammonia slip measurements. These responses can be measured in a variety of ways but are typically measured in the test facility as changes in first bed NOx reduction or changes in ammonia slip versus variations in reactor flow or temperature. The first parametric sequence (preliminary sequence) was an abbreviated parametric test sequence. This test sequence contained a large number of intermediate ammonia measurements with a relatively small number of corresponding ammonia slip measurements. For this reason, the first parametric test results showing flow or temperature dependency on deNOx capability are demonstrated as a function of first bed NOx reduction (calculated from ammonia measurements).

Figure 3 shows the relative first bed NOx reduction as a function of increased reactor flow rate for all catalysts that were operational at that time. The data show a general decline in first bed NOx reduction, as expected. The drop in NOx reduction is mitigated by improvements in mass transfer with increased flow. If no mass transfer limitations were present under the operational conditions, a more severe drop in NOx reduction would probably be noted.

Subsequent parametric test sequences focused more on ammonia slip measurements. Consequently, the effects of flow rate changes on deNOx characteristics are shown as a function of ammonia slip versus flow rate for the second and third parametric sequences. Figure 4 shows the measured ammonia slip versus flow rate using data acquired at a 0.8 NH_3/NOx ratio and 700

°F during the second parametric test sequence. As expected, a general increase in ammonia slip is noted with increasing flow rate. Relatively high slip values for Grace Synox catalyst were measured due to an error in the setting of the NH_3/NOx ratio. For this catalyst, the data represent an NH_3/NOx ratio close to 1.0 rather than the 0.8 NH_3/NOx ratio used for the other catalysts.

Figures 5 through 7 show ammonia slip versus flow rate for three NH_3/NOx ratios (1.0, 0.8, 0.6 NH_3/NOx, respectively) measured during the third parametric test sequence. Figure 5, showing data for the 1.0 NH_3/NOx ratio, is presented to demonstrate a well known effect. The extremely high ammonia slip values at the 1.0 NH_3/NOx ratio indicate that in some cases more ammonia was being injected than there was available NOx to react, thus forcing the reactor to slip the excess ammonia. This high NH_3/NOx ratio tends to control the ammonia slip and masks potential changes in slip due to flow rate variations. Figure 6 and 7, using data at a 0.8 and 0.6 NH_3/NOx ratios, show trends more in keeping with the previously noted results from figure 5 (second parametric test). Again, slight increases in ammonia slip are noted with increasing flow rate.

Figures 8 through 12 show the effects of deNOx capabilities with changes in temperature. As with the flow rate effect data, the first parametric sequence data shows first bed NOx reduction, while subsequent measurements focus on changes in ammonia slip. Figure 8 depicts the relative first bed NOx reduction versus temperature for all catalysts operational at that time. In some cases, fairly significant increases in first bed NOx reduction are noted. Mass transfer limitations tend to inhibit improvements in apparent deNOx activity with increasing temperature. The temperature effect would be nearer to exponential in the absence of mass transfer limitations. Figure 9 shows ammonia slip versus temperature data for the second parametric data set. Relatively little improvement (decrease) is noted in ammonia slip between the 700 °F and 750 °F conditions. At these temperatures, the kinetic rate has likely increased to a point where mass transfer limitations have become controlling and no significant improvements are noted with increased temperature. This is not the case however, for the 620 °F versus 700 °F case conditions. Over this temperature range, relatively significant improvements in ammonia slip are realized with increasing temperature. This can be interpreted to mean that kinetic rate is a fairly significant portion of the overall reaction rate and improvements in this parameter with increasing temperature result in the realization of ammonia slip improvements.

Figures 10 through 12 show data at 1.0, 0.8 and 0.6 NH_3/NOx ratios, respectively for the third parametric test sequence. Figure 10 shows ammonia slip versus temperature for the 1.0 NH_3/NOx ratio and design flow condition. The plot shows fairly significant improvements in ammonia slip for some catalysts while others show nearly constant ammonia slip across the temperature range. As with the slip versus flow rate data, high values of NH_3/NOx ratio tend to control the ammonia slip rather than the temperature. No definite conclusions should be made as to temperature effect using the plot. Figure 11a shows the effect on ammonia slip with variations in temperature at the 0.8 NH_3/NOx ratio. Relatively high ammonia slip values are noted for Grace Synox catalyst due to erosion problems with the catalyst resulting in some flue gas channeling. Subsequent investigation of the catalyst revealed that a manufacturing problem contributed to weak areas in the catalyst which eroded quickly. The catalyst was replaced at the conclusion of the third parametric test sequence. Figure 11b is identical to Figure 11a, but with the Grace Synox catalyst data excluded and the scale changed. This more clearly shows the temperature effect for the remaining catalysts.

The data in figure 11b show that there is relatively little improvement in ammonia slip with increasing temperature across the entire temperature range. Data for NSKK and Cormetech (high dust) show zero slip at the low and mid temperature conditions. These points are plotted as zero since the actual slip measurement was below the detection limit of roughly 0.5 ppm. Thus, the points for these two catalysts at the high temperature condition should not be construed as a significant increase in ammonia slip with increasing temperature. Figure 12 shows data acquired at a 0.6 NH_3/NOx ratio and design flow. This plot is very similar to Figure 11b, again showing little or no improvement in ammonia slip with increasing temperature.

Another important catalyst response to be considered is the ammonia slip versus NH_3/NOx ratio (i.e. NOx reduction). Information of this type is important because it defines the maximum NOx reduction that can be achieved within a particular maximum ammonia slip limit. Figure 13 shows the ammonia slip from each reactor versus the NH_3/NOx ratio. This plot is typical for this type of application showing very sharp increases in ammonia slip as NH_3/NOx ratio nears 1.0. As previously mentioned, NH_3/NOx ratios greater than 1.0 force the catalyst to slip ammonia, since no NOx is available to react with the excess ammonia. The plot clearly shows this effect at NH_3/NOx ratios above 1.0.

SULFUR DIOXIDE OXIDATION MEASUREMENTS

Another important reactivity characteristic of SCR catalysts in addition to NOx reduction activity, is their propensity to oxidize sulfur dioxide. This is an important aspect of SCR catalyst since increased SO_3 can exacerbate problems with equipment downstream of the SCR due to increased formation of acidic deposits. SO_2 oxidation is normally considered to be a first order reaction. Thus, in absence of mass transfer limitations, SO_2 oxidation should have a nearly linear relationship to reactor flow rate and an exponential relationship to temperature. SO_2 oxidation is normally considered to be constant with exposure time based on catalyst supplier historical experience. Figure 14 shows the baseline SO_2 oxidation rate as percent of inlet SO_2 oxidized to SO_3 as a function of catalyst exposure time. A fair amount of scatter is present in data, but in general, no significant trends are noted as a function of catalyst exposure time. Nearly all of the data show oxidation rates of 0.75% or less which was the original design specification for maximum allowable SO_2 oxidation.

Flow rate and temperature effects on SO_2 oxidation are shown in Figure 15 and 16 respectively. This data is from the second parametric test sequence. Figure 15 shows the flow rate effect on SO_2 oxidation for 0.8 NH_3/NOx and 750 °F conditions. The Siemens catalyst data shows relatively high SO_2 oxidation characteristics (in keeping with suppliers quoted rates) and does show a nearly direct linear effect of flow rate on SO_2 oxidation. However, the other catalysts show little or no effect of flow rate on SO_2 oxidation with a relatively constant SO_2 oxidation rate across the flow rate range.

Figure 16 shows the effect of temperature on SO_2 oxidation rate. This plot shows that SO_2 oxidation rate is a much stronger function of temperature than of flow rate, as expected. The effect across the temperature range is relatively linear for most catalyst with the exception of Siemens catalyst which exhibits a more exponential SO_2 oxidation relationship to temperature.

Measurements of SO_2 oxidation subsequent to the second parametric test sequence were limited to only two or three conditions. The SO_2 oxidation rate for 0.8 NH_3/NOx ratio and standard flow at medium and high temperature was examined during the third parametric test sequence. These data are shown in Figure 17. As with Figure 16, the data show a consistent increase in SO_2 oxidation rate with respect to temperature.

GENERAL REACTOR PERFORMANCE MEASUREMENTS

In addition to catalyst performance, reactor performance in terms of NH_3/NOx distributions, particulate distributions, and velocity distributions are critical to the efficient operation of an SCR unit. These parameters are controlled primarily by reactor design rather than catalyst design. Other reactor performance measurements such as reactor pressure drop and N_2O formation are primarily catalyst specific parameters.

Typically, each of these general reactor performance parameters are measured as part of each parametric test sequence. The following discussions outline the general results of these performance measurements.

AMMONIA TO NOx DISTRIBUTION

A balanced NH_3/NOx distribution within an SCR reactor is critical to its efficient operation. Maldistribution of either component can create areas within the reactor where the local NH_3/NOx ratio is very high. This leads to an increase in overall ammonia slip from the reactor and a reduction in deNOx efficiency. Reactor design criteria are set to minimize this problem. In the pilot facility, design criteria are primarily set to maintain a smooth distribution of both ammonia and NOx resulting in an even NH_3/NOx ratio across the reactor. In full scale installations, the ammonia injection grid is tuneable, thus allowing ammonia to be injected in a profile which matches the NOx profile, thereby creating a smooth NH_3/NOx ratio distribution across the reactor. Although the test facility has this tuning capability, in practice most adjustments that have been made were aimed at smoothing the ammonia distribution.

The test facility design criteria requires an ammonia distribution within ± 10% of the average concentration. The NOx distribution within the reactors is normally smooth; therefore this ammonia distribution criteria controls NH_3/NOx ratios within the reactor cross section to within roughly 10% of the average value.

Ammonia distributions are normally measured in the test facility reactors just upstream of the first catalyst beds. Results to date have demonstrated that the ammonia distribution within each reactor is within the ± 10% design criteria originally set.

VELOCITY DISTRIBUTION

The flue gas velocity distribution within an SCR unit is important for several reasons. First, severe maldistributions in velocity make tuning of ammonia injection difficult because the flue gas velocity maldistributions have the same effect as NOx maldistributions. Further exacerbating the problem is that velocity maldistributions are often strong functions of reactor flow rate. Thus, unit load changes would require constant adjustment to the ammonia tuning grid when velocity maldistributions are present. Another concern with velocity maldistribution is the possible erosion impact on the SCR catalyst. Localized high velocities can cause premature catalyst erosion in some areas of the catalyst, thereby reducing the overall life of the catalyst installation.

Measurements of test facility flue gas velocity distributions within the reactors have consistently shown very smooth distributions throughout the reactor (roughly less than ± 5%). The distribution measurements have proven to be very valuable in identifying problems with the catalyst such as areas of fouling or channeling which are indicated by a severe localized change in velocity near the problem area.

PARTICULATE DISTRIBUTIONS

Particulate distributions are an important parameter in SCR units primarily for the potential erosion problems that can occur with particulate maldistributions. Localized high particulate concentrations can accelerate erosion in particular areas, similar to localized high velocities. As previously mentioned, this increased localized erosion can reduce the overall life of the catalyst installation.

Particulate distributions measured within the test facility, normally at the reactor exits, have consistently been very smooth, within ± 5%.

REACTOR PRESSURE DROPS

Reactor pressure drops are controlled primarily by pressure drops across the individual catalyst beds. These catalyst bed pressure drops are dictated, of course, by specific catalyst design. Pressure drop is a major design concern for a utility boiler mainly due to the energy cost involved in overcoming the reactor pressure drop. In SCR retrofit situations, reactor pressure drop becomes critical and often dictates whether or not a fan retrofit or upgrade is required in conjunction with the SCR retrofit.

Long-term catalyst pressure drops are controlled by the original catalyst design and the effectiveness of sootblowing and catalyst cleaning over time. Consistent increases in reactor pressure drop over time indicate that adequate sootblowing/cleaning is not being performed.

Figure 18 shows the pressure drops for each of the SCR reactors as a function of time. These pressure drops represent the summation of pressure drops across all catalyst beds and dummy bed.

N_2O FORMATION

The possible formation of N_2O across SCR reactors was a concern with early SCR experience in the U.S. Subsequent investigations of the problem revealed that this was a sampling/analysis anomaly rather than the true formation of N_2O across SCR catalysts. Measurements at the test facility have included evaluation of N_2O concentrations to further confirm this finding. All measurements to date indicate that the test facility catalysts do not form N_2O during the course of normal operation. Table 4 shows N_2O concentrations acquired during the second parametric tests. The table shows reactor exit N_2O concentrations for each of the catalysts and gives an average reactor inlet N_2O value as measured in the test facility main inlet plenum (prior to splitting of the stream to the individual reactors).

LABORATORY TESTS

Several catalyst characteristics are measured in the laboratory to trace catalyst changes versus flue gas exposure time. Samples are normally extracted from the test facility catalysts on a quarterly basis and sent directly to the individual catalyst suppliers for evaluation. These tests normally examine parameters such as deNOx activity, SO_2 oxidation activity, BET surface area, porosity, and chemical composition.

Of particular interest are laboratory performed deNOx activity measurements. These measurements are very important because they typically demonstrate activity declines before they become apparent in test facility tests. The laboratory tests can often identify the source of catalyst deactivation such as chemical poisoning, loss of surface area, and sintering etc. This type of deactivation data is critical to estimating parameters such as total catalyst life. Figure 19 shows relative deNOx activity versus exposure time for three catalysts. This plot is representative of all catalysts in the test program. The deactivation rates shown are in keeping with catalyst supplier historical experience. No severe declines in deNOx activity are noted which is an encouraging finding, since there has been little previous knowledge of catalyst deactivation rates for U.S. coal applications. This deactivation will of course be tracked throughout the test program and will be used to estimate ultimate catalyst life.

ACKNOWLEDEGMENT

We would like to thank the Southern Research Institute on-site team for their significant contribution in obtaining the data presented here; Mr. Robert Heaphy, Mr. James Garrett, Mr. Randy Hinton, and Mr. Richard Jacaruso. Sincere thanks also go to Mr. Charles Powell for his management of test facility operations, making data acquisition possible. We would also like to thank Mr. James Gibson of Spectrum Systems, Inc. for his diligent efforts in maintaining the SCR gas analyzer system and for his efforts in assuring data quality. Special thanks go to Mr. Gerald Bandura (SCS Engineering) and Mr. Danny Mabire (ICS) for their constant efforts in maintaining the instrumentation and controls for the test facility as well as maintaining and programming the digital control system. Our sincere thanks also go to Mr. Ken Pathak for his unfailing efforts in maintaining the huge quantities of data acquired from the test facility.

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Table 1

Test Facility Inlet Flue Gas Composition

Constituent	ESP Inlet 84 MW	ESP Inlet 43 MW	ESP Outlet 84 MW	ESP Outlet 43 MW
NOx	325	401	332	Not Available
SO_2 (ppm)	2340	1780	2030	1510
SO_3 (ppm)	32	42	14	20
HCl (ppm)	104	89	115	101
NH_3 (ppm)	<0.4	<0.4	<0.4	<0.4
Particulate (gr/dscf)	3.76	2.43	0.0018	BDL*

* Below detection limits

Table 2

SCR Project Catalyst Suppliers

Catalyst Supplier	Reactor Size	Catalyst Configuration
Nippon Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W. R. Grace	Large	Honeycomb
W. R. Grace	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi Zosen	Small	Plate
Cormetech	Small	Honeycomb
Cormetech	Small	Honeycomb (low dust)

Table 3

Project Schedule

Detailed Engineering	1/92 - 12/92
Construction	3/92 - 2/93
Start-up/Shakedown	1/93 - 6/93
Process Evaluation	7/93 - 6/95
Disposition/Final Report	7/95 - 10/95

Table 4

N_2O Concentrations - First Parametric Test

Catalyst	N_2O, ppmv* (dry @ 3% O_2)
Grace Synox	1.8
Cormetech (high dust)	1.8
Haldor Topsoe	1.6
Hitachi Zosen	1.6
Grace Noxeram	1.2
NSKK	1.0
Siemens	1.7

* Average inlet conc. = 2.1 @ main plenum

The following manuscript was unavailable at time of publication.

STATUS OF THE SNOX TECHNOLOGY AND DEMONSTRATION

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ROSEBUD SYNCOAL PARTNERSHIP
SYNCOAL® DEMONSTRATION
Technology Development Update

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ROSEBUD SYNCOAL PARTNERSHIP
SYNCOAL® DEMONSTRATION
Technology Development Update

INTRODUCTION

In the past decade, significant interest has emerged worldwide in beneficiating poor quality low rank coals to improve the economic value and allow abundant regional reserves to be used more efficiently. Generally, the term "low rank coal" or "LRC" means solid carbonaceous materials with a low degree of coalification and includes peat, lignite, brown coals, and sub-bituminous rank coals. LRCs are typically characterized by relatively young geologic settings, high moisture contents, low densities and rather simple open chemical structures. LRCs are found throughout the world and represent a large relatively untapped fuel resource available in North America, Europe and many developing Pacific Rim economies. Unfortunately, the low calorific value, high moisture and high ash contents of the as-mined LRCs severely limit the efficient, economical use of these resources.

Rosebud SynCoal® Partnership's Advanced Coal Conversion Process (ACCP) is an advanced thermal coal upgrading process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel.

The raw coal is processed through two vibrating fluidized bed reactors where oxygen functional groups are destroyed removing chemically bound water, carboxyl and carbonyl groups, and volatile sulfur compounds. After thermal upgrading, the SynCoal® is cleaned using a deep-bed stratifier process to effectively separate the pyrite rich ash.

Rosebud SynCoal's Advanced Coal Conversion Process (ACCP) demonstration enhances low-rank Rosebud seam sub-bituminous coal from the Colstrip area of Montana with a moisture content of 25%, sulfur content of 0.8%, and a normal heating value of 8,600 Btu/lb. The upgraded coal product, SynCoal®, has a moisture content as low as 1%, sulfur content as low as 0.3%, and a heating value of nearly 12,000 Btu/lb.

Construction of the 300,000 ton per year (tpy) demonstration project adjacent to Western Energy Company's Rosebud mine unit train loadout facility near the town of Colstrip in southeastern Montana was completed in 1992. An extended startup and shakedown period lasted until August 1993. The facility has produced nearly at-design capacity since January 1994. Rosebud SynCoal's demonstration plant is sized at about one-tenth the projected throughput of a multiple processing train commercial facility. The next generation of facilities are expected to become standardized 100 tons per hour (TPH) process trains.

Demonstration operations and testing began in April 1992 and are continuing. Initial operations discovered the normal variety of equipment problems which delayed operational and process testing. As operational testing has proceeded, the product quality issues that have emerged are dustiness and resistance to spontaneous combustion. The SynCoal® product has met the original BTU, moisture and sulfur specifications and operations have reached a reliable production level at about 110% of design capacity. The project team is continuing extensive process testing aimed at resolving product issues in response to market requirements.

The ACCP Demonstration Facility is a U.S. Department of Energy (DOE) Clean Coal Technology Program Project. The original funding commitment was $69 million with 50% funding from the DOE and 50% from the Rosebud SynCoal Partnership. DOE and Rosebud recently agreed to extend the project until November 1997 with DOE funding 23.5% of the extended process optimization and commercial evaluation activities, increasing the total funding to $105.7 million and DOE's commitment to a total of $43.125 million.

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The Rosebud SynCoal Partnership is a venture involving Western SynCoal Company and Scoria Inc.. Western SynCoal is a subsidiary of Western Energy Company (WECo) which is a subsidiary of Entech Inc., Montana Power Company's non-utility group. Scoria Inc. is a subsidiary of NRG Energy Inc., Northern States Power's non-utility group.

STATUS OF DEVELOPMENT

Development and demonstration of the SynCoal® technology is continuing at the 300,000 ton per year SynCoal® plant at Western Energy's Rosebud Mine near Colstrip, Montana. The demonstration facility has operated at 111% of design capacity and 83% availability during the first five months of 1995, reaching as much as 129% of design capacity and 94% availability during the month of April. An annual maintenance and facility modification outage was conducted in June to replace the lower section of the process heat exchanger, install soot blowers, add circulating oil lubrication systems for the first stage and cooler fans, add baffling in the process furnace, and perform general maintenance.

Rosebud SynCoal is developing facility designs and equipment concepts around 100 TPH process units that can be added in multiples to make facilities at virtually any production capacity desired. A listing of the most significant events in the history of the ACCP development is provided in Appendix A.

DEMONSTRATION PROCESS DESIGN DESCRIPTION

The ACCP is a low rank coal upgrading and conversion process using low pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and convert the coal followed by a water spray quench and a vibratory fluidized stage to cool the coal. The solid impurities are then removed from the dried coal using pneumatic separators.

The design throughput of the demonstration plant is 450,000 tpy (1,640 tpd) of raw coal, providing 242,000 tpy (886 tpd) of coarse SynCoal® product and 66,000 tpy (240 tpd) of SynCoal® fines (minus 20 mesh). The fines are to be collected and sold, giving a combined product rate of 308,000 tpy (1,126 tpd) of high-quality, clean SynCoal® product. The central processes are depicted in Figure 1, the Process Flow Schematic.

A more complete description of the SynCoal® demonstration facility is contained in the papers presented in previous Clean Coal conferences.

ACCP PROCESS TESTING

The ACCP demonstration project has allowed the SynCoal organization to test two different North Dakota lignites and a Wyoming sub-bituminous coal as well as the regular Rosebud sub-bituminous feedstock. Process test summaries are shown in Figures 2 through 5.

On May 27, 1993 about 190 tons of screened lignite from BNI Coal's Center Mine was processed at the SynCoal® demonstration facility (see Figure 2, BNI Lignite Process Test). At that time the SynCoal® facility was configured to operate on a single process train and was extremely limited by the fines handling system capacity. However good product recovery and product qualities were obtained.

On September 20, 1993 a second test on 532 tons of screened BNI lignite was conducted (See Figure 3, BNI Lignite Process Test). This test significantly improved the coarse SynCoal® product yield while obtaining comparable product recoveries and product qualities. Approximately 190 tons of coarse BNI SynCoal was test burned on September 22, 1993 in the cyclone boiler at Minnkota Power Cooperative's 225 MW Milton R. Young 1 (see the SynCoal® Product Testing Section).

On October 19, 1993 about 290 tons of screened Knife River Coal's Gascoyne Lignite was processed with good results but not the same level of improvement as the Center lignite exhibited (see Figure 4 - Gascoyne Lignite Process Test).

On May 17, 1994, 681 tons of screened sub-bituminous coal from the Gillette, Wyoming area was processed with very good product yield and product quality results (see Figure 5 - Powder River SynCoal Process Test). The greater improvement in the fines indicate the process conditions may not have been quite severe enough for optimum results. The granular SynCoal® was DSE conditioned and shipped to Dairyland Power's J.P. Madgett plant. Dairyland's plant personnel observed dustiness and some self heating presenting potential handling and storage issues for any long term application.

Moisture is essentially eliminated from all coals tested using the SynCoal® process. This moisture removal is due to thermal dehydration of the coal particle both physical and chemical, and the chemical condensation reactions which the feedstock experiences during its residence in the high temperature environment of the second-stage reactor bed.

The moisture-free analysis of the feedstock and the upgraded product also show that, to a large extent, both the volatile matter and the fixed carbon content is retained in the SynCoal product. This phenomenon is significant and desirable, because normally raw coal, when subjected to the temperatures of the ACCP, would undergo devolatilization and substantial gasification. The ACCP products are much more desirable fuels because of their extremely good ignitability and complete combustion (low LOI) causing many observers to comment that it "burns with a short natural gas like flame" except the opaque flame provides more radiant heat providing an additional benefit to many operations.

The reduction in total sulfur is due primarily to the mechanical removal of pyrites during the cleaning step. However, the ability to remove these pyrites is a result of the chemical repolymerization and consequent shrinkage of the organic components of the coal, which causes fracture release of the ash or mineral components. A small amount of organic sulfur is volatilized from the coal in the form of hydrogen sulfide (H_2S) during the upgrading process.

OPERATING STATUS

Construction of Rosebud SynCoal's ACCP Demonstration Facility was completed during the first quarter of 1992 at a total cost of approximately $35 million. Initial equipment startup was conducted from December 1991 through March 1992. Initial operations discovered the normal variety of equipment problems. The project's startup and operations groups worked together to overcome the initial equipment problems and achieve an operating system. The fines handling equipment was undersized originally and required a significant modification to expand the capability of this system. The lack of fines handling capacity prevented the facility from achieving full production rate and limited operating hours due to frequent fines handling equipment failures. This modification was completed in August 1993. The new fines handling system has allowed full production and more reliable operations. Table 1 shows the improved operations since September 1993. Additional modifications were performed during the second annual outage during August/ September 1994 to improve process gas distribution. The modifications resulted in poor gas flow in the process gas furnace which damaged the furnace inlet plenum. Further repairs, modifications and operational changes were necessary in November 1994 to achieve the desired results. These efforts combined with continuing improvements resulted in low forced outage rates, high availabilities and record production throughout early 1995.

SYNCOAL PRODUCT TESTING

As shown in Figure 6, the SynCoal® products monthly average moisture content has declined and become more consistent during the past two years resulting in increasing heating value as measured in Btu/lb. Figure 7 shows that the SO_2 potential has remained low and the ash content (lbs of ash/MMBtu) has become more consistent and decreased slightly. During the same period, plant availability, monthly production and sales have generally improved as shown in Figure 8.

In spite of these improvements the SynCoal® product has continued to display a tendency towards self heating that was not expected. The project's technical and operating team has conducted an extensive process testing program in order to determine the cause of the product's lack of stability. A number of approaches have been partially successful; however, to date, the demonstration product has not met the level of resistance to spontaneous combustion that was apparent in the earlier pilot plant work. This has reduced the storage life and as a result delayed full-scale test burn programs.

J.E. Corette Testing.

An initial test burn program was conducted at Montana Power's J.E. Corette station. A significant amount of handling and storage testing was conducted in preparation for the full-scale test burn program.

An initial SynCoal® testburn program, was conducted intermittently from March, 1994 through July, 1994 at MPC's J.E. Corette plant in Billings, Montana. The primary objective of the testburn was to determine what reduction in sulfur dioxide emissions could be achieved by burning blends of DSE conditioned SynCoal® and Western Energy Company's Area D raw coal. In addition, the effects on boiler performance were also observed, modeled, and analyzed to determine the benefits of burning a SynCoal® blend.

The results of the testburn indicate that the level of sulfur dioxide emissions decreased when firing a SynCoal® blend as expected based on the reduction of SO_2 in the blends versus Area D coal. While burning 100 percent Area D raw coal, typical SO_2 emissions were 1.48 lbs/MBtu. The SO_2 levels were reduced by 12 percent when burning a 50 percent DSE Conditioned SynCoal®/50 percent Area D raw coal and 23 percent while burning a 79 percent DSE Conditioned SynCoal®/21 percent Area D coal.

In each case, the boiler efficiency did improve when firing a SynCoal® blend versus 100 percent Area D raw coal as determined in the modeling studies. While burning the 50/50 blend, the boiler efficiency increased by nearly 1 percentage point and more than 1½ percentage points using the 79/21 blend.

During the testburn of the 75 percent blend, the plant did not reduce load to deslag and was able to maintain a load of 170 GMW for a 24-hour period. The duration of the 75 blend test was

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relatively short, and it was not determined whether these trends would continue during a longer test.

One shipment of a 95 percent SynCoal® blend was delivered to the plant and a testburn of this blend was scheduled to run for two weeks. The 95 percent SynCoal® blend test was stopped after the first shipment due to a problem with mill skidding. The mills were not adjusted to correct this problem while the test was running and thus very little, if any, data is available from this blend test.

During the entire testburn program, the dust levels of the blended product were acceptable and no product instability was reported.

During July an additional 50/50 blend testburn was conducted on a clean boiler coming after Corette's annual maintenance outage. Data from July 20, 22 and 27 was then used to construct a mathematical unit model of the J.E. Corette Unit that contains both the boiler and turbine cycles. This model was then used to predict operations on Rosebud Area D fuel, SynCoal® DSE fuel and SynCoal® fuel. These predictions were then compared to identify changes in unit parameters with each of the three fuels.

On the basis of these comparison, Rosebud Area D fuel yielded a 163 MW gross output with a net unit heat rate of 10,370 Btu/Nkwhr. This was considered the base case and the maximum dependable generation utilizing Rosebud "D" fuel. Using the same model, operation on SynCoal® DSE yielded a maximum 170.6 MW gross output with a net unit heat rate of 9,995 BTU/Nkwhr. This output was limited by a furnace exit gas temperature equal to that predicted with Rosebud Area D fuel.

Operations modeled using SynCoal® yielded a maximum 170.5 MW gross output with a net unit heat rate of 9,619 BTU/Nkwhr. This output was limited by the 1,116,000 lb/hr secondary superheater flow rate limitation.

At these maximum predicted ratings, the SO_2 emission rate in lb/MMBtu dropped to 58.8 percent and 57.4 percent respectively of the emission rate when firing Rosebud Area D fuel. There was a commensurate drop in SO_2 emissions on a ton/hour basis to 59 percent and 55.9 percent, respectively of the Rosebud Area D values.

Lee E. Alt, J.E. Corette's Plant Superintendent has high praise for SynCoal®:

> "During the last two years we extensively tested SynCoal® raw sub-bituminous coal blends in the J.E. Corette plant. We have learned that there are benefits from the burning of such a blend in our boiler. Firing with a 50% SynCoal® blend not only reduces our SO_2 emissions, we have seen an increase in available net plant capacity and reduced slag buildup in the radiant furnace area. It is apparent that SynCoal® helps maintain a cleaner boiler which reduces or eliminates our normal deslagging operation of reducing load on a scheduled basis, at a cost of 300 MW to 400 MW per deslag. The SynCoal® use allows more continuous generation and at times could help prevent natural gas peaking units from coming on-line within the regional electric grid.
>
> In my opinion SynCoal® not only has potential as an environmentally compatible fuel, but also as a deslagging fuel for improving operating profiles in constricted pulverized coal units."

M.R. Young 1 Testing

Approximately 190 tons of coarse BNI SynCoal was test burned on September 22, 1993 in the cyclone boiler at Minnkota Power Cooperative's 225 MW Milton R Young 1. The thermal results generally matched the computer modeling predictions; however, as a result, Minnkota's operations group was deslagging with additional fuel oil firing, consuming approximately 50,000 gallons of fuel oil in the 12 to 18 hour period prior to initiating the SynCoal® test with little benefit. Although the test team debated about the detrimental impacts of the slagged cyclone barrels on the proposed test, it was decided to proceed as planned. SynCoal was fed to three of the cyclones and raw lignite to three effectively firing the left side with SynCoal® and the right side with raw lignite. The results were amazing. Not only did the cyclones firing SynCoal® deslag within 45 minutes of initiating the SynCoal® firing, but the furnace walls and convection pass also deslagged to some extent. This was particularly amazing, given that the SynCoal® was converted from the same parent lignite that slagged the boiler in the first place. The operating personnel observed that the three SynCoal® fired cyclones had a brighter hotter flame than the lignite fired cyclones and the slag melted in the entire boiler and tapped through the monkey holes (slag taps in the furnace bottom) even better than when deslagging with fuel oil. Analysis of the test data showed an increase in boiler efficiency from 82.2% to 86.3%, which decreased the furnace exit gas temperature depressing the superheated steam temperatures and reducing unit capacity. Total boiler air flow decreased 13%, reducing the forced draft and induced draft fans. The net result was a 123 Btu/kWh improvement in total plant gross heat rate.

Kiln Operation Testing

Rosebud SynCoal has supplied Ash Grove Cement's Montana City production facility with a variety of SynCoal® products since January 1994, and has developed a long term steady customer supplier relationship. Although no formal testburns have been conducted, Ash Grove's operating personnel have informally reported more consistent operations and product quality using a SynCoal®/petroleum coke fuel blend as well as improved thermal efficiency. Dan Peterson, Ash Grove Plant Manager stated in a July 6, 1994 letter:

> "[SynCoal®] has a uniform heat value, thereby allowing us to operate our cement kiln very stable. This is resulting in improved quality of our product and a slight increase in our production capacity.
>
> As you know, we have burned many different coals and other fuels, including Canadian gas, depending on the economics at the particular time. We feel that the SynCoal® product yields a very stable flame in our kiln, thus making it our fuel of choice. The uniformity of the product is great, comparable to natural gas! A solid fuel is also preferable in that it produces an opaque flame which results in additional radiant heat. Natural gas produces a translucent flame which has only conductive and convective heat. The additional radiant heat in our burning zone helps our reaction rate."

In addition to supplying Ash Grove's coal requirements, Rosebud SynCoal has supplied both Continental Lime's Townsend and Holnam's Trident, Montana facilities for periods of time in the past. Rosebud SynCoal is expecting to reestablish deliveries to Continental Lime this fall and continue testing with Holnam in the spring/summer of 1996. Holnam provided Rosebud SynCoal with a synopsis of their testing during November 1994:

"No adjustments were made to the coal mill when grinding Syn-Coal and coal mill fineness averaged 99.86 passing the 50 mesh, 98.68 passing the 100 mesh and 79.51 passing the 200 mesh. Feed-O-Weight moisture averaged 1.7 percent and firing pipe moistures averaged 1.0%.

The Syn-Coal was started while burning Type I-II clinker and continued for the next four days before changing to three tanks of Type I-II SR clinker for the next four days and then back to Type I-II clinker for the last day. Kiln operations were very steady as noted by kiln revs being maintained at 72 RPH, the burning zone controlled easily, kiln amps stayed low, dust loss was consistent and about the average and we were not pushed. While on the last tank of I-II Sr clinker the exit draft increased from 2.1, 2.2 to 2.4 to 2.6 inches, the kiln amps increased somewhat but still were only 400 to 430 amps and by the next day the exit draft dropped back to the 2.2 inch range.

The MMBTU's were about the same or possibly a little better then for Kirby coal, the fuel was very consistent with almost no fluctuations in quality and the burning zone was easy to maintain. Other than controlling the cooler dust collector temperature, the kiln ran very good, with several of the CRAs (process operators) commenting that it was somewhat like burning gas."

Cyclone Boiler Testing

During March 1995, a 3-day SynCoal® handling and combustion test was conducted at Packaging Corporation of America's cyclone boiler, Unit No. 8 at Tomahawk, Wisconsin. Generally, the handling test showed that unconditioned SynCoal® was too dusty for the existing handling system indicating that facility modifications would be necessary for a long term use. The combustion test was a success maintaining good slag flow and monkey hole tapping even though load swings from full to half load and back were prevalent.

Continuing Test Efforts

Rosebud SynCoal's marketing efforts have become intensely focused upon the industrial boiler and direct fired kiln segments primarily due to the limited capacity (330,000 tpy) of the existing demonstration plant, the covered hopper car shipping, and the requirement for inerted storage. Typically, industrial coal users can derive greater direct benefits from the high quality and manufactured consistency of SynCoal® than utility boiler operators. Additionally, many industrial facilities already have enclosed silo type fuel storage and handle the smaller volumes "odd lot" train movements.

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As a result of this intense focus additional testburns are anticipated in a variety of industrial facilities later this year. SynCoal has an aggressive plan for testing SynCoal® in standard and modified spreader stoker applications. Additionally, testing SynCoal® as a fuel oil replacement in large scale boiler deslagging operations is scheduled during this summer.

The industrial market niche is the most lucrative for SynCoal® since these users can take better advantage of the specific benefits of SynCoal®, adapt quickly and will share the additional benefits. As a result, the ongoing marketing efforts will be focused to continue expanding the industrial market applications for SynCoal®.

PROJECTIONS FOR THE FUTURE

The Rosebud SynCoal Partnership intends to commercialize the process by both preparing coal in its own plants and by licensing the SynCoal technology to other firms. The long term target markets are primarily the U.S. utilities, the industrial sector and Pacific Rim export market. Current projections suggest the utility market for this quality coal is approximately 60 million tons per year with potential industrial markets of 38 million tons per year at an $18-20 per ton price in the Powder River Basin. The Partnership is currently working on three potential semi commercial projects tentatively located in Wyoming, North Dakota and Montana. Each project represents significant enhancements toward the ultimate goal of a standardized process train and modular commercial design that will allow development of future facilities sized to match the needs of the specific markets anywhere from 500,000 to 1,000,000 million tons per year each.

The Wyoming project is a stand alone mine mouth design. The North Dakota project is integrated into Minnkota Power Cooperative's mine mouth power plant with the product sales offsite to regional markets. The Montana project is designed as an expansion of the existing demonstration facility.

CONCLUSION

The ACCP is a relatively simple, low pressure, medium temperature coal upgrading and conversion process that produces a high quality, very consistent, synthetic, high volatile bituminous grade fuel. The synthetic upgraded coal product exhibits the characteristics of reduced equilibrium moisture level, reduced sulfur content and increased heating value. The SynCoal product retains a majority of its volatile matter and demonstrates favorable combustion characteristics.

Although difficulties have been encountered, SynCoal's technical and operating team are resolving the issues and SynCoal marketing is starting to expand rapidly. The ACCP Demonstration program is continuing with a complete team effort involving all three of the major participants. It is expected that the ACCP demonstration will continue to produce test results and technology development through the extended demonstration resulting from DOE's expanded funding and time schedule and the continued efforts of the Rosebud SynCoal Partnership.

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APPENDIX A

ADVANCED COAL CONVERSION PROCESS
SIGNIFICANT EVENTS

September	1981	Western Energy contracts Mountain States Energy to review LRC upgrading concept called the Greene process.
November	1984	Initial operation of a 150 lb/hr continuous pilot plant modeling the Greene drying process at Montana Tech's Mineral Research Center in Butte, Montana.
December	1984	Initial patent application filed for the Greene process, December 1984.
January	1986	Initiated process engineering for a demonstration-size Advanced Coal Conversion Process (ACCP) facility.
October	1986	Completed six month continuous operating test at the pilot plant with over 3,000 operating hours producing approximately 200 tons of SynCoal®.
October	1986	Western Energy submitted a Clean Coal I proposal to DOE for the ACCP Demonstration Project in Colstrip, Montana, October 18, 1986.
November	1987	Internal Revenue Service issued a private letter ruling designating the ACCP product as a "qualified fuel" under Section 29 of the IRS code, November 6, 1987.
February	1988	First U.S. patent issued February 16, 1988, No. 4, 725,337.
May	1988	Western Energy submitted an updated proposal to DOE in response to the Clean Coal II solicitation, May 23, 1988.
December	1988	Western Energy was selected by DOE to negotiate a Cooperative Agreement under the Clean Coal I program.
March	1989	Second U.S. patent issued March 7, 1989, No. 4, 810,258.
September	1990	Signed Cooperative Agreement, after Congressional approval, September 13, 1990.
September	1990	Contracted project engineering with Stone & Webster Engineering Corporation, September 17, 1990.
December	1990	Formed Rosebud SynCoal Partnership, December 5, 1990.
December	1990	Started construction on the Colstrip site.
March	1991	Novated the Cooperative Agreement to the Rosebud SynCoal Partnership, March 25, 1991.
March	1991	Formal ground breaking ceremony in Colstrip, Montana, March 28, 1991.

APPENDIX A (Continued)

December	1991	Initiated commissioning of the ACCP Demonstration Facility.
April	1992	Completed construction of the ACCP Demonstration Facility and entered Phase III, Demonstration Operation.
June	1992	Formal dedication ceremony for the ACCP Demonstration Project in Colstrip, Montana, June 25, 1992
July	1992	Identified a variety of mechanical and process issues.
May	1993	Conducted process test on BNI lignite achieving nearly a 60% sulfur reduction in an 11,000 Btu product.
June	1993	Initiated deliveries of SynCoal® under a contract with industrial customer.
August	1993	State evaluated emissions, and the ACCP process is in compliance with air quality permit. ACCP Demonstration Facility went commercial on August 10, 1993, having resolved major mechanical issues.
September	1993	Conducted second BNI lignite process test and short combustion test with surprisingly good deslagging results.
October	1993	Tested a second North Dakota lignite as a potential process feedstock, achieving nearly 11,000 Btu/lb heating value.
December	1993	Signed a Letter of Intent with Minnkota Power Cooperative to attempt development of a SynCoal® facility at M.R. Young plant site near Center, ND.
May	1994	Testing Wyoming Powder River sub-bituminous coal as a potential process feedstock, achieving 11,800 Btu/lb heating value in the resultant product.
June	1994	Successfully concluded 30-day, 1000 mile covered hopper rail car test shipment.
August	1994	Concluded J.E. Corette testing and moved into a regular supply arrangement.
September	1994	Steven J. Heintz was killed in the crash of U.S. Air Flight 427 on September 8.
September	1994	Held an open house and tour on September 20 to raise public and market awareness.
March	1995	Conducted a 3-day testburn in PCA's cyclone boiler with good combustion results but identified a need to upgrade their handling system.
March	1995	Set monthly record sales volume of 29,383 tons, 118 percent of original design performance.
April	1995	Set new production record for third consecutive month, operating at 94% availability and 129% of capacity.

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Figure 1

Process Flow Diagram

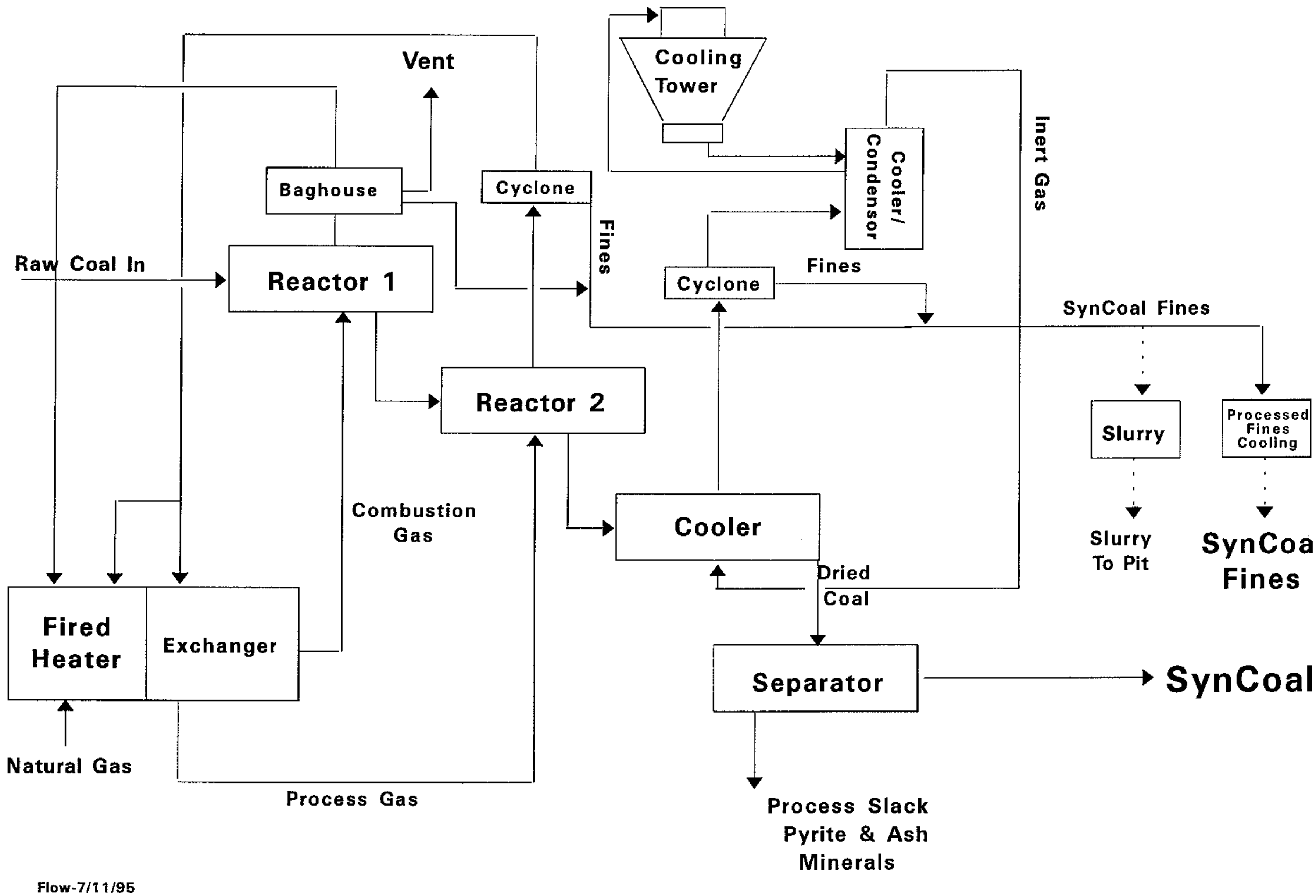

Figure 2

BNI LIGNITE PROCESS TEST
May 27, 1993

- Processed 190 tons @ 20.5 tph wo/interruption

- Recovered 64% as Clean Product and Fines

- Demonstrated Upgrade Results:

	FEED	PRODUCT	FINES
TPH	20.5	6.1	7.0
% Moisture	37.3	4.1	6.1
% Ash	6.1	7.7	9.5
% MAF Volatile	47.7	45.5	45.4
% MAF Fixed Carbon	52.1	54.4	54.6
% Sulfur	1.11	0.74	1.05
Btu/lb	6,972	11,126	10,404
SO_2/MMBtu	3.18	1.33	2.02
% Eq Moisture	33.7	20.1	N/A

- BNI SynCoal Ground Stabilized 45 ton Pile Lasted Over 28 Days Before Disposal

- Moisture Regain 4.1% to 6.2% over 18 days

- Btu Retention - 11,126 Btu/lb to 10,660 Btu/lb over 18 days

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Figure 3

BNI LIGNITE PROCESS TEST

September 20, 1993

- Processed 532 tons @ 32.1 tph wo/interruption
- Adjusted Recovery of 62% as Clean Product and Fines
- Demonstrated Upgrade Results:

	FEED	PRODUCT	FINES
TPH	32.1	16.0	3.7
% Moisture	36.2	7.4	10.3
% Ash	6.5	6.5	9.5
% MAF Volatile	47.4	45.7	45.3
% MAF Fixed Carbon	52.6	54.3	54.7
% Sulfur	1.07	0.78	1.06
Btu/lb	7,064	10,718	9,914
SO_2/MMBtu	3.03	1.46	2.14
% Eq Moisture	35.0	20.1	21.9

- Test Burned 190 tons of BNI SynCoal at MR Young 1 - Sept. 22, 1993 Effects on Unit as Expected:

  Temperatures in the Convection Passes Dropped Depressing Steam Temperatures and Reducing Capacity 8.8 MW

  Visual Observation of Three Cyclones Firing SynCoal Showed Better Combustion with a Brighter Hotter Flame

  Melted Slag Out Better than Fuel Oil and Improved Monkey Hole Tapping

  Total Boiler Air Flow Dropped 13% Resulting in Reduced Load on the FD and ID Fans

  Boiler Efficiency Increased from 82.2% to 86.3%

  Plant Total Gross Heat Rate Improved by 123 Btu/KWh

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Figure 4

GASCOYNE LIGNITE PROCESS TEST

October 19, 1993

- Processed 290 tons @ 29.5 tph wo/interruption
- Recovered 55% as Clean Product and Fines
- Demonstrated Upgrade Results:

	FEED	PRODUCT	FINES
TPH	29.5	10.7	5.4
% Moisture	41.0	3.7	7.8
% Ash	8.0	9.8	11.6
% MAF Volatile	50.7	48.7	48.2
% MAF Fixed Carbon	49.3	51.3	51.8
% Sulfur	1.16	1.18	1.43
Btu/lb	6,324	10,972	10,070
SO_2/MMBtu	3.67	2.15	2.84
% Eq Moisture	39.1	17.4	24.6

- Gascoyne SynCoal Ground Stabilized 10 Ton Pile Lasted Over 35 Days Before Disposal
- Moisture Regain 3.7% to 7.6% over 35 days
- Btu Retention - 10,972 Btu/lb to 10,400 Btu/lb over 35 days

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Figure 5

POWDER RIVER SYNCOAL PROCESS TEST

May 17, 1994

- Processed 681 tons @ 60.2 tph wo/interruption

- Recovered 73% as Clean Product and Fines

- Demonstrated Upgrade Results:

	FEED	PRODUCT	FINES[1]
TPH	60.2	34.8	9.5
% Moisture	28.1	4.5	6.2
% Ash	4.9	6.6	6.3
% MAF Volatile	47.4	46.6	44.6
% MAF Fixed Carbon	52.6	53.4	55.4
% Sulfur	0.34	0.45	0.48
Btu/lb	8,727	11,805	11,339
SO_2/MMBtu	0.78	0.76	0.84
% Eq Moisture	28.4	14.0	16.8

- Approximately 139 tons shipped to Dairyland Power as DSE Conditioned Product

- One railcar shipped as covered hopper car test - held over 30 days in the rail car

- Results indicate 98 percent energy recovery

[1]Unaccounted weight included as fines.

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Figure 6 - SynCoal Quality Trends

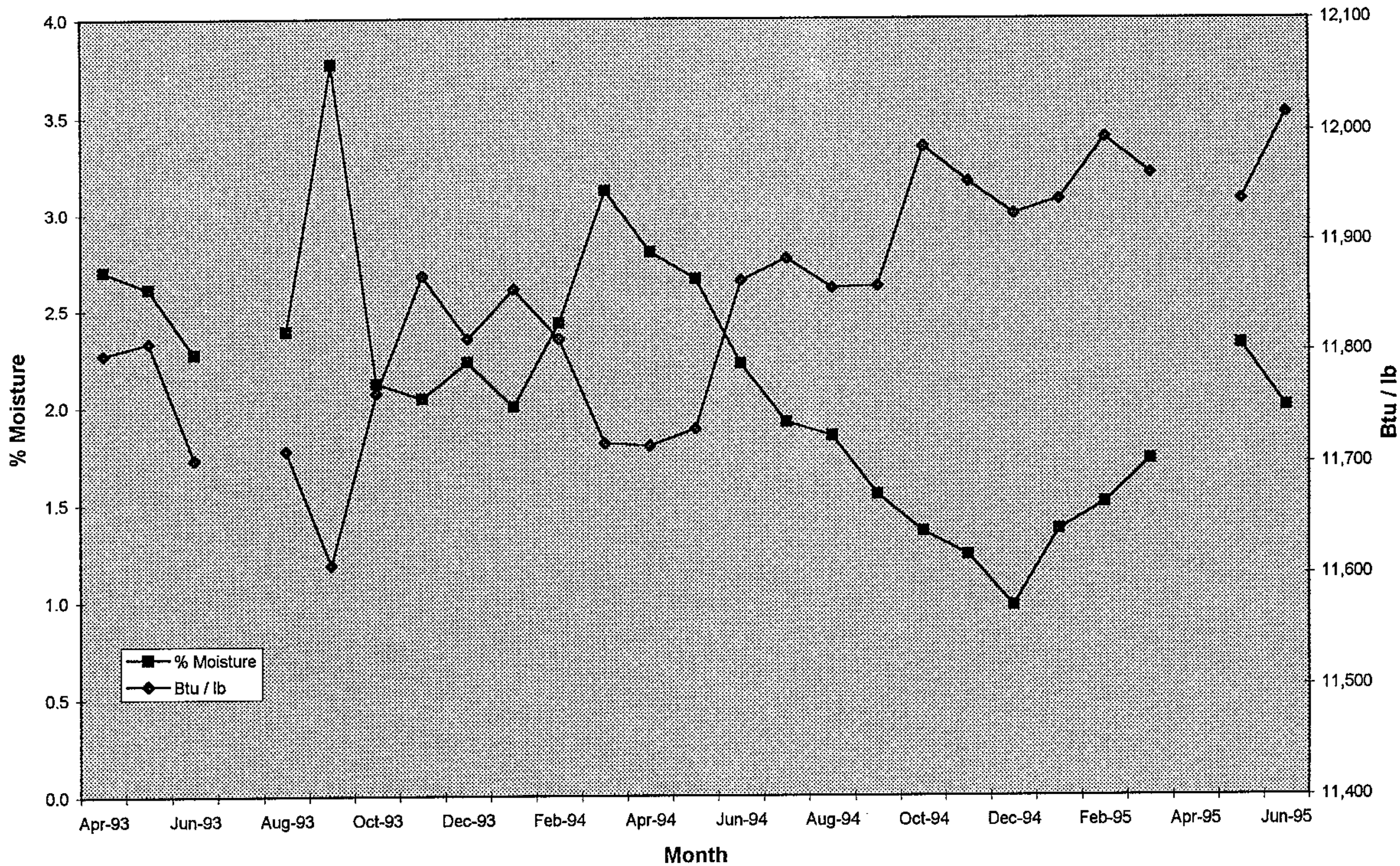

Figure 7 - SynCoal Quality Trends

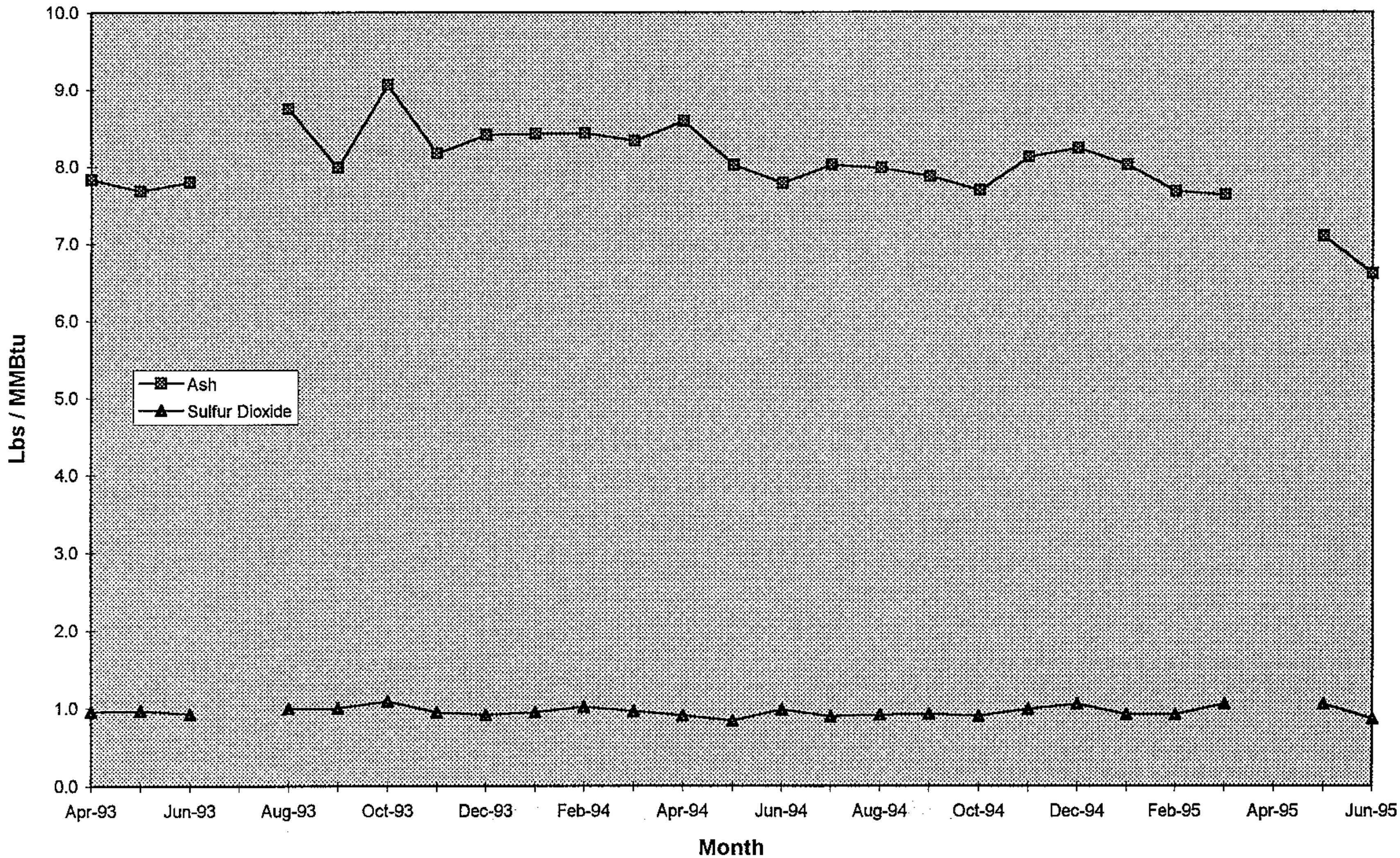

Figure 8 - SynCoal Production & Sales

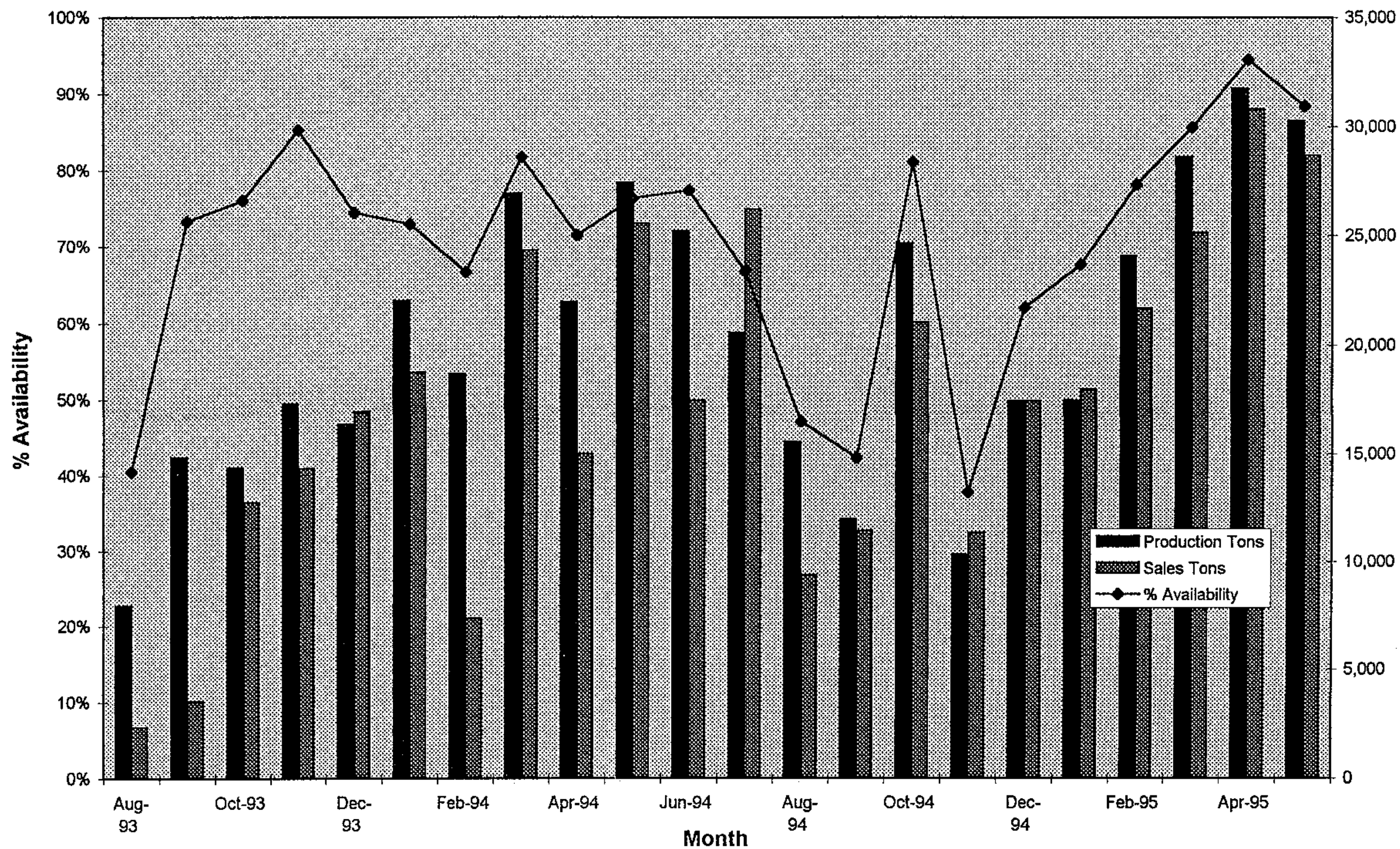

TABLE 1
SYNCOAL DEMONSTRATION OPERATING STATISTICS

MONTH	PRODUCTION AVAILABILITY	FORCED OUTAGE RATE	TONS PROCESSED	CAPACITY FACTOR	SHIPMENTS
Mar-92	4%	96%	700	2%	181
Apr-92	7%	89%	411	1%	212
May-92	12%	77%	2,757	7%	-
Jun-92	13%	81%	2,496	7%	214
Jul-92	7%	56%	1,436	4%	-
Aug-92	17%	60%	1,860	5%	61
Sep-92	44%	33%	8,725	24%	1,672
Oct-92	13%	63%	2,292	6%	523
Nov-92	58%	28%	6,946	19%	2,386
Dec-92	11%	80%	1,063	3%	317
Jan-93	53%	26%	8,626	23%	3,658
Feb-93	44%	18%	6,544	19%	915
Mar-93	44%	34%	6,565	17%	629
Apr-93	49%	30%	8,514	23%	745
May-93	47%	39%	9,175	24%	768
Jun-93	15%	26%	2,752	7%	199
Jul-93	0%		-	0%	655
Aug-93	50%	19%	13,427	35%	2,361
Sep-93	73%	18%	14,371	66%	3,545
Oct-93	76%	11%	23,528	62%	12,753
Nov-93	85%	14%	27,930	76%	14,349
Dec-93	74%	9%	26,009	68%	16,951
Jan-94	73%	17%	34,979	92%	18,754
Feb-94	67%	25%	29,280	85%	7,369
Mar-94	82%	13%	41,891	110%	24,351
Apr-94	72%	26%	34,438	91%	15,022
May-94	76%	17%	39,440	101%	26,355
Jun-94	77%	23%	36,657	99%	18,772
Jul-94	67%	33%	34,026	89%	26,227
Aug-94	47%	11%	24,645	63%	9,146
Sep-94	42%	23%	20,327	55%	12,578
Oct-94	81%	16%	34,908	91%	21,036
Nov-94	38%	62%	16,418	46%	11,169
Dec-94	62%	27%	25,258	66%	18,478
Jan-95	68%	32%	33,372	87%	17,965
Feb-95	78%	22%	38,325	111%	21,717
Mar-95	86%	4%	42,674	112%	29,383
Apr-95	94%	1%	47,818	129%	30,827
May-95	88%	5%	43,752	114%	28705
	TOTAL		683,473		400,341

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SO_x-NO_x-Rox Box™ TECHNOLOGY REVIEW AND GLOBAL COMMERCIAL OPPORTUNITIES

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ABSTRACT

The SO_x-NO_x-Rox Box™ or SNRB™ process is a combined sulfur dioxide (SO_x or SO_2), nitrogen oxides (NO_x) and particulate (Rox) emissions control technology developed by Babcock & Wilcox (B&W) in which high removal efficiencies for all three pollutants are achieved in a high-temperature baghouse. A 5 MW_e equivalent demonstration of the technology co-sponsored by the U.S. Department of Energy (DOE), the Ohio Department of Development/Ohio Coal Development Office (OCDO), and the Electric Power Research Institute (EPRI) was completed in 1993 at the Ohio Edison R.E. Burger Plant.

This unique, high-temperature baghouse/catalyst configuration provides for integrated particulate capture, SO_2 removal, and NO_x reduction. A brief overview of this technology is followed by a summary of operating results. Economic comparisons are presented, including a sensitivity analysis of major cost and performance factors which vary on a world-wide basis.

INTRODUCTION

The SNRB™ emission control process is a combination of three technologies:

- Dry sorbent injection for SO_2 removal
- Selective Catalytic Reduction (SCR) for NO_x abatement
- High-temperature fabric filtration for particulate control

These technologies are combined as illustrated in Figure 1. The process is a post-combustion emissions control technology which is integrated into a power plant or industrial process between the combustion zone and the downstream heat recovery equipment.

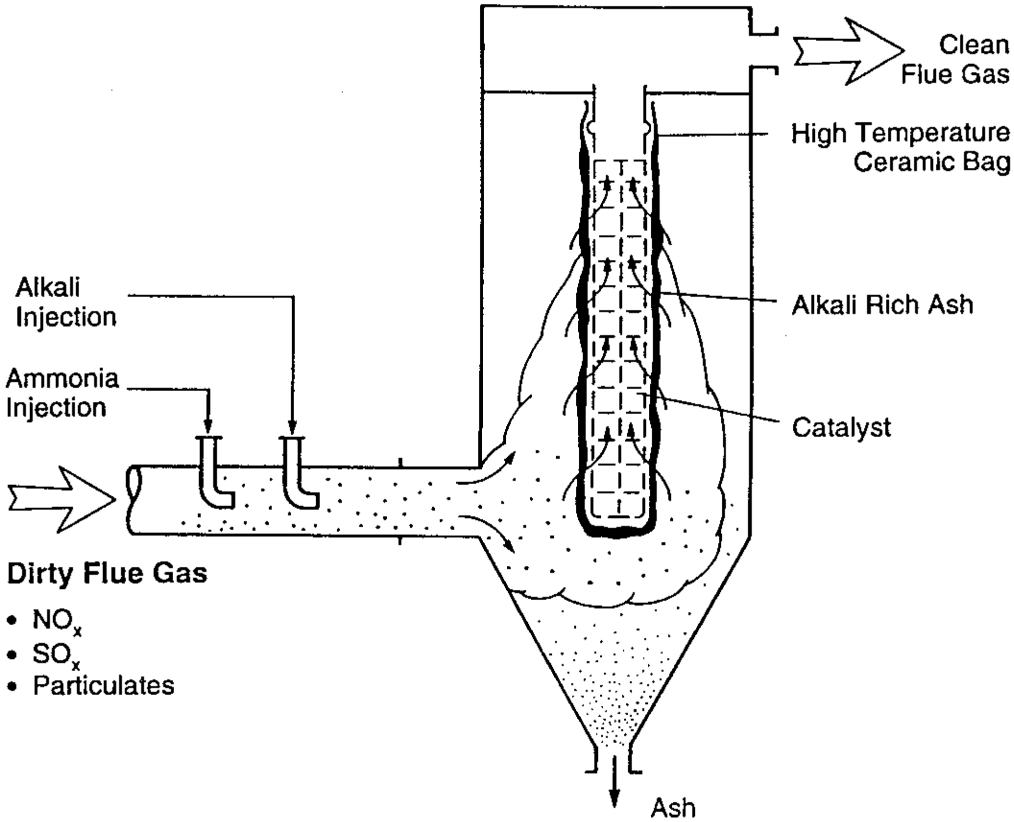

Figure 1 — SNRB™ Process Schematic.

The SNRB process includes several innovative characteristics which provide for a unique, high efficiency combined emissions control process. Operation of a pulse-jet baghouse at high temperatures requires that the filter bags be made of a fabric that can withstand exposure to flue gas at 800 to 900°F, while maintaining high particulate collection efficiency and flexibility. Integration of the SCR catalyst to minimize unreacted ammonia emissions and permit bag cleaning using conventional pulse-jet technology required development of a circular monolith catalyst. The unique features of the process provide several distinct advantages in comparison with competing emissions control technologies. These general advantages include:

- Multiple emissions control in a single component
- Low plan area space requirements
- Operating simplicity
- Flexibility for optimal overall control economics
- Ability to implement emissions reduction in phases, without incurring high initial retrofit costs
- Enhanced SCR operating conditions
- Improved SO_2 sorbent utilization
- Dry materials handling

In certain applications, the initial SNRB system capital costs are lower than a combination of conventional systems for comparable emissions control.

Development of the SNRB process at Babcock & Wilcox began with pilot testing of high-temperature dry sorbent injection for SO_2 removal in the 1960s. Integration of NO_x reduction was evaluated in the 1970s. Pilot work in the 1980s focused on evaluation of various NO_x reduction catalysts, SO_2 sorbents and integration of the catalyst with the baghouse. This early development work led to the issuance of two U.S. Process patents to Babcock & Wilcox - No. 4,309,386 and No. 4,793,981. An additional patent application for improvements to the process is pending. The Ohio Coal Development Office (OCDO) has been instrumental in working with B&W to develop the process to the point where a larger scale demonstration of the technology is feasible.

SNRB™ FLUE GAS CLEAN-UP DEMONSTRATION PROJECT

The DOE Clean Coal Technology Program demonstration was a key component in the SNRB technology commercialization effort. The demonstration provided for optimization of the catalyst integration arrangement, evaluation of operating conditions for maximizing simultaneous emissions control, investigation of alternative bag fabrics, and evaluation of SO_2 sorbents for enhancing SO_2 removal. The project also permitted an assessment of the bag and catalyst suppliers' ability to produce these key components to commercial specifications.

The SNRB Flue Gas Clean-Up Demonstration Project was selected for funding in the second round of the Clean Coal Technology Program. The $13.3 million project was co-sponsored by the U.S. Department of Energy, the Ohio Coal Development Office, Babcock & Wilcox, the Electric Power Research Institute and Ohio Edison. In-kind contributions were provided by 3M, Norton Chemical Process Products and Owens-Corning Fiberglas. DOE provided 45.8% of the total project funding. The Cooperative Agreement with DOE was signed in December, 1989 and the project was completed in August, 1994.

The project scope was comprised of four primary test programs:

- Base demonstration project
- Filter fabric assessment
- Alternative bag demonstration
- Air toxics emissions testing

The overall project objectives included demonstration of greater than 70% SO_2 removal and 90% or higher reduction of NO_x emissions while maintaining particulate emissions below 0.03 lb/10^6 Btu. A 5 MW_e slipstream demonstration of the technology was the focus of the project. The demonstration, located at Ohio Edison's R.E. Burger Plant, incorporated commercial scale bag/catalyst assemblies. The components of the 5 MW_e SNRB demonstration facility are summarized in Table 1.

Table 1 — SNRB™ Demonstration Facility

- Six compartment pulse-jet baghouse
- Commercial scale bag/catalyst assemblies
- Independent injection/baghouse operation temperature control
- Pneumatic materials handling
- Dry sorbent storage and injection
- Anhydrous ammonia storage and injection

The SNRB process treated a slip stream of flue gas from the Burger Plant boiler #8. The gas tie-in was between the economizer and the combustion air heater where the flue gas temperature was approximately 600 to 650°F. This nominal 160 MW_e pulverized coal, wall-fired B&W boiler has been in operation since 1955. Ohio Edison fired a blend of bituminous coals in the boiler with an average sulfur content of 3 to 4%. At the SNRB process inlet, the flue gas contained 2000 to 3000 ppm SO_2, 350 to 500 ppm NO_x and 3 to 4 grains/scf particulates.

The SNRB demonstration facility was operated for approximately 2,300 hours with sorbent and ammonia injection for emissions control. The facility experienced more than 25 cold start-up cycles. Despite these numerous start-ups, no degradation of the catalyst or filter bags was observed. The initial performance goals were exceeded. It is particularly worth noting that significantly higher SO_2 removal was obtained by optimizing the sorbent injection and baghouse operating temperatures and through the use of modified lime hydrates. In three periods of planned continuous operation for more than 200 hours each, system availability averaged 99%.

SNRB™ DEMONSTRATION PERFORMANCE HIGHLIGHTS

The emissions control performance observed at the SNRB demonstration over a range of operating conditions has previously been reported in detail[1,2,3]. This discussion will focus on a brief review of key operating results.

Table 2 summarizes performance with commercial grade hydrated lime injection and operation of the baghouse at 855°F. This data reflects the average of several tests conducted at similar operating conditions at various times throughout the demonstration program.

Table 2 — SNRB™ Emissions Control Performance

	Emissions ($lb/10^6$ Btu) Boiler Outlet	Emissions ($lb/10^6$ Btu) SNRB Baghouse
SO_2	4.313	0.544
NO_x	0.660	0.067
Particulate	5.660	0.018
	Stoichiometry (Inlet Basis)	
	Ca/S	1.95:1
	NH_3/NO_x	0.84:1

SO_2 Emission Control

SO_2 emission control at the demonstration was optimized through evaluation of the sorbent injection and baghouse operating temperatures, operation over a range of Ca/S stoichiometric ratios and investigation of alternative SO_2 sorbents. Holmes, et. al., has discussed the effects of each of these primary factors on SO_2 removal in detail[2]. With the baghouse operating above 830°F, outlet SO_2 emissions were reduced to less than 1.2 $lb/10^6$ Btu, using Ca/S ratios of 1.4 and above.

A commercial grade hydrated lime was used for most of the operation of the SNRB demonstration. In addition, two alternative limes were used with the potential to improve SO_2 removal. Slight modifications were made to the operation of a commercial hydrator to produce finer mass mean diameter products through the addition of lignosulfonate or a sugar solution as the hydrator[4]. At a Ca/S ratio of 2, both alternative hydrates yielded approximately an 8% improvement in performance over the base sorbent, pushing SO_2 removal above 90%.

The use of sodium bicarbonate, $NaHCO_3$, as the SO_2 sorbent permits SO_2 emission control at a lower temperature. The observed performance with sodium bicarbonate injection for SO_2 control is summarized in Table 3. The system inlet SO_2 concentration ranged from 4 to 5 lb/10^6 Btu.

Table 3 — SO_2 Removal with Sodium Bicarbonate

	SO_2 Removal	SO_2 Emissions
Baghouse Operation @ 450 - 460°F		
Na_2/S Ratio: 1.0	84%	0.78 lb/10^6 Btu
Na_2/S Ratio: 2.0	98%	0.08 lb/10^6 Btu
Baghouse Operation @ 600 - 625°F		
Na_2/S Ratio: 1.0	74%	1.01 lb/10^6 Btu
Na_2/S Ratio: 2.0	92%	0.40 lb/10^6 Btu

The sodium bicarbonate was 98% less than 200 mesh with a surface area of 4.5 m²/gram. A 95% $NaHCO_3$ purity was measured. In general, the use of $NaHCO_3$ results in a higher sorbent utilization than is possible with hydrated lime.

The following key points characterize SNRB system SO_2 removal performance in the demonstration test program:

- Injection of the sorbent directly upstream of the baghouse at 825 to 900°F resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1200°F.
- With the baghouse operating above 830°F, injection of a commercial hydrated lime sorbent injected at Ca/S ratios of 1.8 and above resulted in SO_2 removals over 80%.
- SO_2 removals of 85 to 90% were obtained with Ca utilizations of 40 to 45%, based on inlet concentrations. This is significantly higher than the 60% removal, 30% utilization typical of other dry $Ca(OH)_2$ injection processes.
- The use of $NaHCO_3$ as the SO_2 sorbent permitted high SO_2 removal efficiencies at significantly reduced baghouse operating temperatures.
- SO_2 emissions were reduced to less than 1.2 lb/10^6 Btu with a 3 to 4% sulfur coal with Ca/S ratios as low as 1.5 and Na_2/S ratios less than 1.

<u>NO_x Emission Reduction</u>

The zeolite SCR catalyst installed at the demonstration was formulated for optimal performance at temperatures above 750°F. The NC 300 zeolite catalyst does not contain any heavy metal promoters. In this temperature region, outlet NO_x emissions were reduced to less than 0.05 lb/10^6 Btu with NH_3/NO_x ratios of 0.85 and above, and the baghouse operating temperature above 800°F. NO_x emission reduction for baghouse operating temperatures of 790 to 865°F is summarized in Table 4.

Table 4 — Average NO_x Emissions at the Burger Plant Demonstration

	NO_x Emissions
SNRB™ Inlet	0.54 to 0.72 lb/10^6 Btu
SNRB™ Outlet	
NH_3/NO_x ratio: 0.5	0.30 lb/10^6 Btu
NH_3/NO_x ratio: 0.7	0.14 lb/10^6 Btu
NH_3/NO_x ratio: 0.9	0.03 lb/10^6 Btu

The emission of unreacted ammonia downstream of an SCR unit is a primary concern with SCR system operation. Periodic ammonia slip measurements were obtained using a modified EPA Method 5 sample train over a range of operating conditions. Ammonia slip levels below 5 ppm were measured for the SNRB process, well within the limits typically found for commercial SCR installations.

Key SNRB NO_x reduction observations from the demonstration tests can be summarized as follows:

- 90% NO_x emission reduction was readily achieved with ammonia slip limited to less than 5 ppm. This performance reduced NO_x emissions to less than 0.10 lb/10^6 Btu.
- NO_x reduction was insensitive to temperature over the catalyst design temperature range of 700 to 900°F.
- Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.
- Turndown capability for tailoring the degree of NO_x reduction, by varying the rate of ammonia injection, was demonstrated for a range of 50 to 95% NO_x reduction.
- No appreciable physical degradation or change in catalyst activity was observed over the duration of the test program.
- The degree of oxidation of SO_2 to SO_3 over the zeolite catalyst appeared to be less than 0.5%. SO_2 oxidation is a concern for SCR catalysts containing vanadia to promote the NO_x reduction reaction.
- Leach potential (TCLP) analysis of the catalyst after completion of the field tests confirmed that metal concentrations were well below regulatory limits and the catalyst remained non-hazardous for disposal.

Particulate Emissions

EPA Method 5 sampling downstream of the baghouse confirmed that particulate emissions were consistently below the New Source Performance Standard of 0.03 lb/10^6 Btu. Variations in particulate emissions could not be correlated with the hydrated lime injection rate, air-to-cloth ratio, baghouse pressure drop, bag cleaning frequency or combination of modules in service. The average of more than 30 baghouse particulate emission measurements was 0.018 lb/10^6 Btu.

A detailed discussion of particulate emission control at the demonstration has been provided by Evans, et. al.[1].

A summary of key observations related to particulate collection at the SNRB demonstration follows:

- Hydrated lime injection increased the baghouse inlet particulate loading from an average of 5.6 to 16.5 lb/10^6 Btu (3.2 to 9.3 grains/SCF).
- Emission testing with and without the SCR catalyst installed revealed no apparent difference in particulate collection efficiency.
- On-line cleaning with a pulse air pressure of 30 to 40 psi was sufficient for cleaning the bag/catalyst assemblies.
- Typically, one of the five baghouse modules in service was cleaned every 30 to 150 minutes.

By-product Characterization

Operation of the demonstration generated a total of approximately 830 tons of fly ash and by-product solids. Approximately 30 tons of this material was used to evaluate potential applications. The remaining solids were disposed of in a solid waste landfill.

Table 5 provides a typical composition of the baghouse solids with injection of commercial hydrated lime at a Ca/S ratio of 2. The coal contained approximately 3.5% sulfur and 12% ash.

Table 5 — SNRB™ Solids Composition

Constituent	Weight % of Total
Fly ash	32.8
$CaCO_3$	23.9
$CaSO_4$	20.5
$CaSO_3$	15.4
CaO	7.4

The key characteristics of the solids collected in the SNRB baghouse were as follows:

- The free moisture of the baghouse product was typically below 0.5% by weight, and the product showed little affinity for picking up moisture even after outdoor storage for several months.
- Leach potential (TCLP) was well below regulatory limits for solid waste disposal.
- No ammonia was detected in the baghouse solids.
- The pH of the solids ranged from 10.5 for sodium bicarbonate injection to 12.4 for hydrated lime injection.

A variety of potential uses for the solids have been investigated. Spreadability tests for soil amendment applications were performed with several types of agricultural lime spreaders. These tests indicated that the low bulk density and moisture content of the material may require an intermediate pelletizing step for efficient application of the material for agricultural liming. The SNRB solids were found to have a pozzolanic activity index above the minimum required for fly ash to be used in concrete. The final compressive strength of the mortar, using SNRB solids, was comparable to that of the base mortar indicating the solids could be used as a partial cement replacement to lower the cost of the concrete.

Corrosion Study

A concern when applying SCR to coal-fired boilers is the oxidation of SO_2 to SO_3. Subcontractor testing indicated the SNRB system SCR configuration results in minimal, if any, net oxidation of SO_2 to SO_3. During testing with lime injection, the SO_3 concentration in the flue gas downstream of the SNRB baghouse was measured in the range of 5 to 10 ppm. To some extent, the SO_3 content of the flue gas determines the minimum exit temperature at which the combustion air heater can be operated to minimize corrosion of the heat transfer surfaces. This minimum exit temperature influences the net thermal efficiency of the power plant.

SNRB SYSTEM ECONOMIC EVALUATION

A cost model has been used to evaluate the projected SNRB system capital costs for various new and retrofit utility boiler emissions control applications. A previous economic comparison of the SNRB system with a combination of SCR, dry scrubbing and a baghouse indicated SNRB capital costs are competitive with this combination for smaller units burning lower sulfur coal[5]. The capital cost of the SNRB system was projected to be 20% less than the combination of conventional technologies for a 100 MW_e plant burning 1.5% sulfur coal. Levelized costs expressed as U.S.$/ton of SO_2 and NO_x removed were also lower for SNRB. The SNRB system capital costs also compare favorably with alternative combined emissions control technologies.

For utility boiler applications, the SNRB system appears to be most cost competitive in the 50 to 150 MW_e size range. Potential markets for the technology in this target market exist on a global scale. Global marketing efforts require an expanded view of potential financing conditions and technical performance requirements that may be encountered throughout the world. The impacts of factors such as the opportunity cost of capital (discount rate), plant capacity factor, operating costs and SO_2 emission control requirements on SNRB system economics are examined in the following discussion.

SNRB Retrofit System Costs

Figure 2 summarizes the levelized costs for retrofit application of the SNRB system to a wide range of unit sizes for three coal sulfur levels. These levelized costs include capital, fixed operation and maintenance (O&M), and variable operating costs. The capital charge levelizing factor is based on 10% interest over a 15 year period.

The costs in Figure 2 do not reflect the reduction of particulate emissions. Including the reduction in particulate emissions significantly reduces the capital cost on a $/ton of pollutant removed basis. For example, the projected emissions reduction costs for a 150 MW_e unit are $553/ton of SO_2 and NO_x removed and $270/ton of SO_2, NO_x and particulate emissions reduction. Since the high-temperature baghouse is an integral part of the SNRB system and a significant component of the capital cost, total emissions reduction is a more logical base than simply SO_2 and NO_x. However, to permit comparison with other combined SO_x and NO_x control processes, the $/ton of SO_2 and NO_x removed basis will be used. No credit is assumed for reduction of additional acid gas emissions such as HCl.

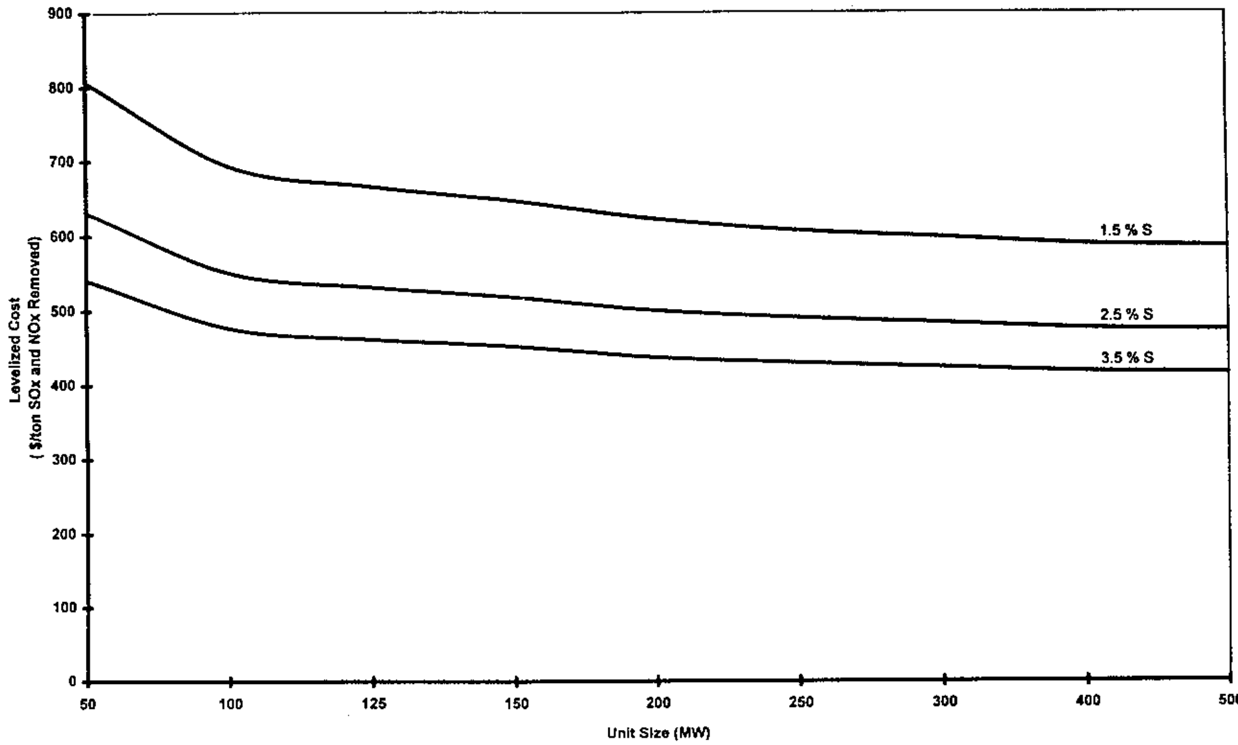

Figure 2 — Retrofit SNRB System Costs.

These retrofit system costs are based on the following key SNRB system assumptions:

- Scope of equipment supply
  - High temperature baghouse, bags and SCR catalyst
  - Anhydrous ammonia storage and injection system
  - Hydrated lime storage and injection system
  - New air heater
  - Auxiliary economizer
  - Modification of existing flues and ducts
  - Modification of existing ash handling and storage system
  - Boiler controls upgrade

- SNRB Operating Costs

Hydrated lime	$70/ton
Anhydrous ammonia	$215/ton
By-product solids disposal	$9.29/ton
Auxiliary power	$0.05/kW-hr

- System Performance

Overall plant capacity factor	65%
Uncontrolled emissions	SO_2 4.31 lb/10^6 Btu
	NO_x 1.02 lb/10^6 Btu
SO_2 removal	85% @ Ca/S ratio of 1.85
NO_x reduction	90% @ NH_3/NO_x ratio of 0.90

No operating cost credits are assumed for overcompliance and generation of SO_2 emission allowances or beneficial use of the solid by-product. The total capital costs include a 25% retrofit factor, a 10% technology contingency factor and a 25% project contingency factor.

For higher coal sulfur content, the capital cost per ton of pollutant removed becomes relatively insensitive to unit size for generating capacities above 100 to 150 MW_e. For a given unit size, the cost per ton of pollutant removed is also less sensitive to coal sulfur content as the sulfur content increases. This reflects the significance of the fabric filter costs in the total capital cost.

SNRB System Costs for New Plants

The SNRB system levelized costs for new utility boiler applications are summarized in Figure 3 for a wide range of boiler sizes and three coal sulfur levels. The costs shown include levelized, installed capital cost, fixed O&M and variable operating costs. As with the retrofit system, the capital charge levelizing factor is based on 10% interest for 15 years. As with the retrofit system costs presented in Figure 2, expressing costs on a U.S.$/ton of SO_2 and NO_x removed basis does not adequately address the integrated particulate removal aspect of the SNRB system. If these costs are used for comparison with other combined SO_2 and NO_x system costs, the cost of particulate emissions control must be added to the latter. With the exception of the variable unit size, the key assumptions noted in the following base plant discussion were used for generation of the costs in Figure 3.

The total capital costs for a new plant are significantly lower than those for a retrofit unit of the same size. The costs for a new plant do not include modifications to existing economizer and air heater heat transfer surfaces or re-routing of existing flues. The new plant costs do, however, include the complete cost of the ash handling equipment and storage system.

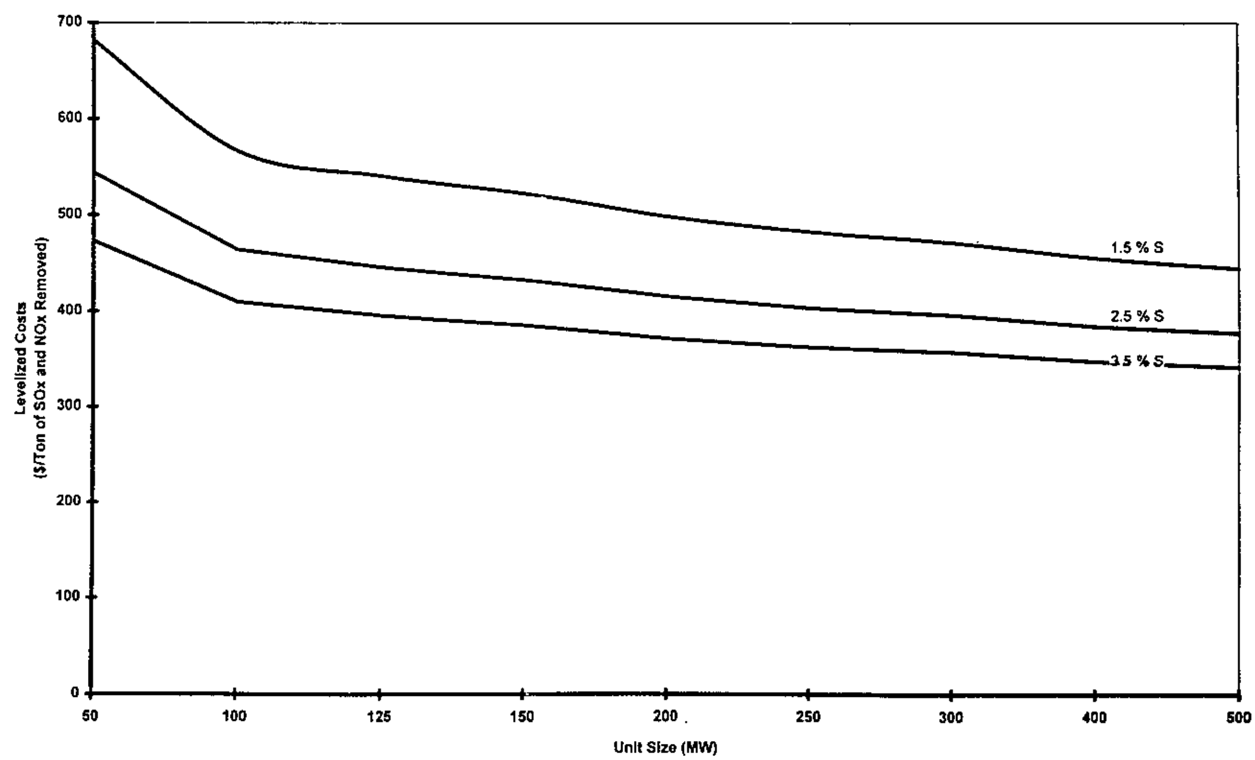

Figure 3 — New Plant SNRB System Costs.

The levelized costs expressed in \$/ton of SO_2 and NO_x removed are not sensitive to unit size above approximately 100 MW_e when a higher sulfur coal is fired. The levelized costs for a 500 MW_e unit are within 17% of the costs for a 100 MW_e unit. On this cost basis, there does not appear to be a significant economy of scale.

Base Plant Economic Discussion

Application of SNRB for controlling emissions from a new 100 MW_e boiler firing 2.5% sulfur coal is used as the base case for evaluating the impact of several key parameters on capital and operating costs. The base plant costs were developed based on the following key assumptions:

- Scope of equipment supply
  - High temperature baghouse, bags and SCR catalyst
  - Anhydrous ammonia storage and injection system
  - Hydrated lime storage and injection system
  - Solid by-product transport and storage system

- SNRB operating costs

Hydrated lime	\$70/ton
Anhydrous ammonia	\$215/ton
By-product solids disposal	\$9.29/ton
Auxiliary power	\$0.05/kW-hr

- System performance

Overall plant capacity factor	85%
Uncontrolled emissions	SO_2 4.31 lb/10^6 Btu
	NO_x 1.02 lb/10^6 Btu
SO_2 Removal	85% @ Ca/S ratio of 1.85
NO_x Reduction	90% @ NH_3/NO_x ratio of 0.90

For the base case, no credit was assumed for enhanced boiler efficiency or generation of marketable SO_2 emission allowance credits.

A breakdown of the base case installed equipment costs is presented in Figure 4. Notice that hydrated lime receiving, storage and injection equipment represents only 9% of the installed equipment cost. Compliance SO_2 removal efficiency and the potential to generate SO_2 emission allowances is attained for a relatively small additional equipment cost.

The NO_x removal equipment includes the ammonia receiving, storage and injection equipment and the SCR catalyst. The particulate control fraction represents the costs of the baghouse, filter bags and by-product solids handling and storage equipment. The solids handling equipment accounts for approximately 40% of the particulate system costs. This cost breakdown is relatively consistent for installations of 50 to 150 MW_e. As the unit size increases, the NO_x subsystem cost component fraction increases and the particulate subsystem costs decrease while the SO_2 subsystem cost remains consistent at about 9% of the total.

Analysis of Figure 4 provides insight into the potential for phased installation of the complete SNRB system. If future NO_x control requirements are uncertain, initial system capital costs can be reduced by 21% to about \$175/kW while still retaining the capability for adding catalyst and ammonia injection to achieve required NO_x emission levels at a future date. If SO_2 emission control is of secondary importance, or can be supplemented in the short term through the use of low-sulfur

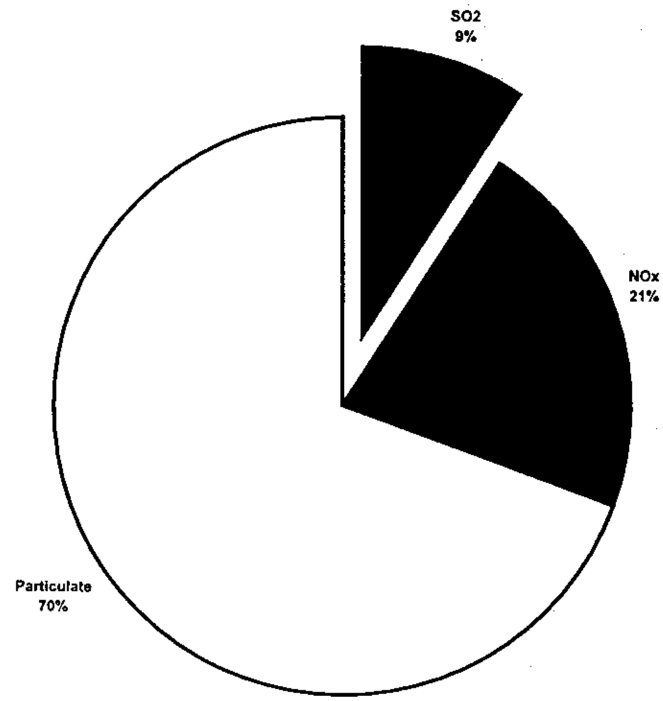

Figure 4 — Installed Equipment Cost Breakdown.

coal, the initial capital investment can be slightly reduced. The SNRB system configuration provides for relatively easy addition of the hydrated lime injection system at a later date. SNRB provides an excellent hedging strategy for an application using low-sulfur coal switching for near term emissions compliance. The baghouse eliminates concerns of particulate emissions control system degradation. A relatively minor future capital investment in the reagent storage and injection system, $34/kW for the base plant, will provide compliance operation should low sulfur coal pricing or availability become a concern.

A breakdown of the base plant operating costs is provided in Figure 5. Operating costs for the base plant are dominated by hydrated lime consumption. This analysis assumed the hydrated lime would be purchased in bulk powder form. For some applications, it may be more cost effective to purchase lime and hydrate it on site. Delaying installation and operation of the SO_2 equipment reduces the operating costs for the base plant from $505/hr to $106/hr reflecting lower solids disposal costs and lower fixed costs in addition to eliminating the hydrated lime costs.

For the base SNRB system, ammonia and auxiliary power costs are relatively minor contributions to the total operating costs. The baghouse pressure drop is the biggest fraction of the total power use. However, even at the base plant condition of 12 inches pressure drop, this is not a significant operating cost component. Doubling the auxiliary power costs to $0.10/kW-hr increases the relative significance from 6% to 11.5% of the total operating costs.

Solid by-product disposal costs are approximately 13% of the total operating costs for the base plant. A reduction in disposal costs from $9.29/ton to $5.00/ton results in a 7% reduction in variable operating costs. Utilization of even 50% of the by-product solids, assuming zero value, will reduce variable operating costs by 8%.

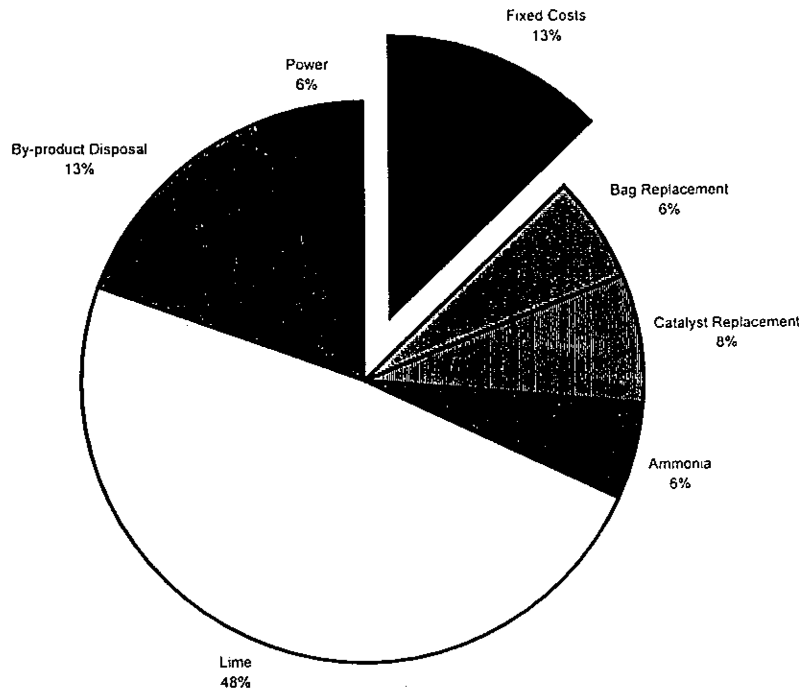

Figure 5 — SNRB System Operating Cost Components.

The base case economic analysis does not assume credit for the generation of SO_2 emission allowances even though SO_2 emissions are reduced to 0.62 lb $SO_2/10^6$ Btu. Assuming a compliance level of 1.2 lb $SO_2/10^6$ Btu and the current Phase II allowance price of approximately \$130/ton, operation of the base plant generates a potential revenue stream of \$266,000 per year. This revenue is sufficient to offset the SNRB system auxiliary power costs or the ammonia costs. At \$200/ton, the revenue stream increases to over \$400,000 per year.

Influence of Plant Capacity Factor

The percentage of time the system is available for operation and is operated at maximum capacity is reflected in the plant capacity factor. Operation at higher capacity factors reduces the levelized cost of the SNRB system on a \$/ton SO_2 and NO_x removed basis since more pollutants are removed for the same capital investment. This is shown in Figure 6. The simple nature of the SNRB system operations provides for a very high availability to operate at full load on demand.

Impact of Design SO_2 Removal

The SNRB system can be designed to provide a specific level of SO_2 removal to meet required compliance emissions limits. A system designed for 50% removal would be expected to have a lower capital cost than a system designed for 90% removal. However, a system designed for higher removal efficiency may provide a lower emission reduction unit cost. Cost analysis on a levelized \$/ton SO_2 and NO_x removed basis may be used to quantify the trade-off between higher capital costs and more cost efficient operation. Figure 7 illustrates that higher capital cost can be offset by improved efficiency but there may be a point beyond which the marginal benefit of improving efficiency is no longer economical. The costs in Figure 7 do not include any credit for generating SO_2 emission allowances.

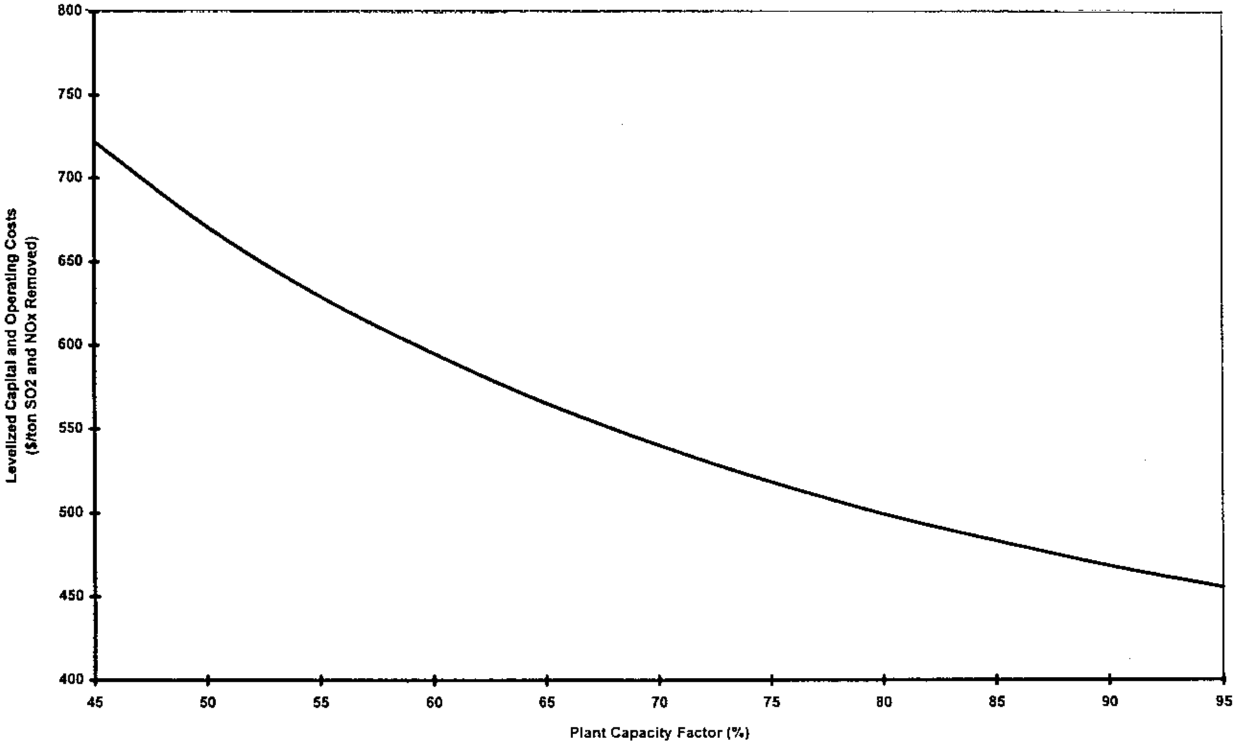

Figure 6 — Impact of Plant Capacity Factor on Levelized SNRB Costs.

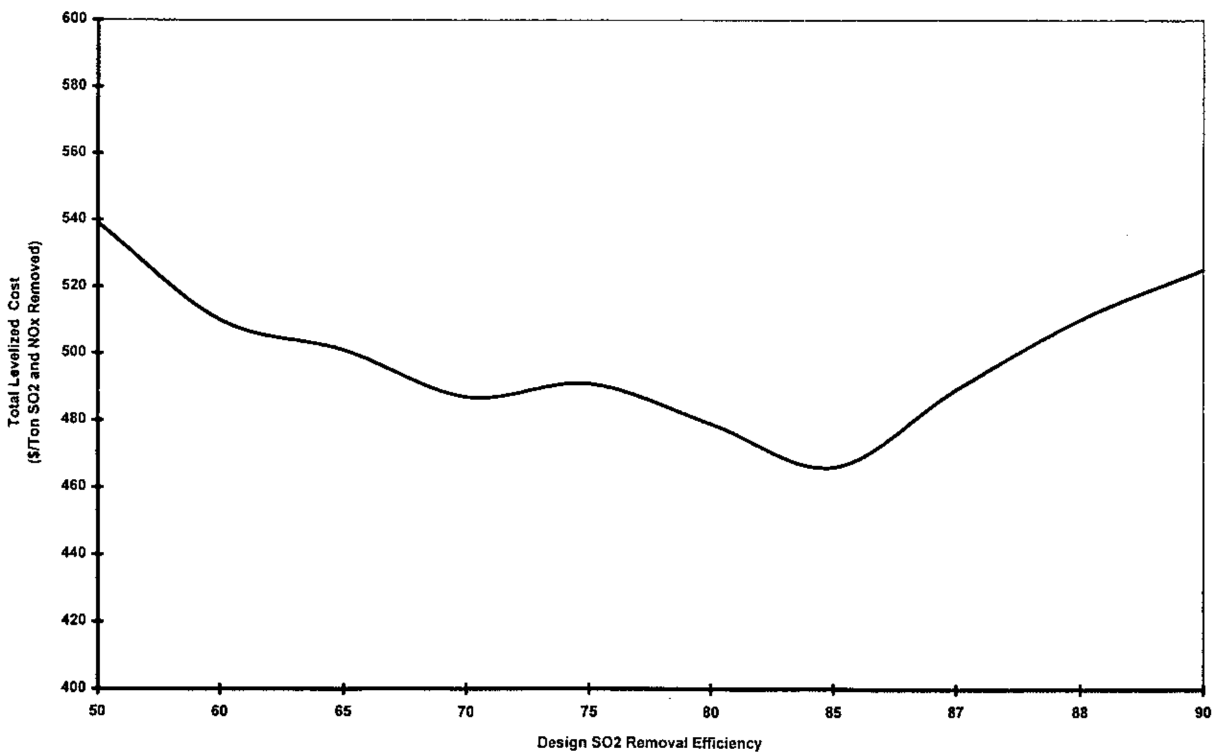

Figure 7 — Impact of SO_2 Removal Design and Operation on SNRB System Costs.

Impact of Financing Arrangements

A wide variety of financing conditions is encountered in global marketing of emission control technologies. The impact of effective interest rates and loan periods on SNRB system costs is illustrated in Figure 8. Notice that financing the project beyond 15 to 20 years does not result in significant levelized capital cost savings.

COMMERCIALIZATION

In the United States, Phase 1 of the Clean Air Act Amendments of 1990 is now in effect. Relatively few of the plants impacted by Phase 1 have installed scrubbers to meet SO_2 compliance. A large proportion of plants have met compliance by fuel switching or purchasing SO_2 emission credits on the open market. Based on the current market price of SO_2 allowances, Phase 2 compliance is likely to rely heavily on fuel switching and allowance trading, at least during the initial stages. The delay in installing scrubbers for Phase 2 may provide an opportunity for clean coal technologies such as SNRB to be utilized as a future compliance option[6].

The potential global market for SNRB and other clean coal technologies is substantial. U.S. government estimates of the global environmental market exceed $400 billion annually by the year 2000. The fastest-growing markets for environmental technologies are in Asia and Latin America[7].

United States Market

The current value of Phase II SO_2 allowances and the availability of low sulfur coals has

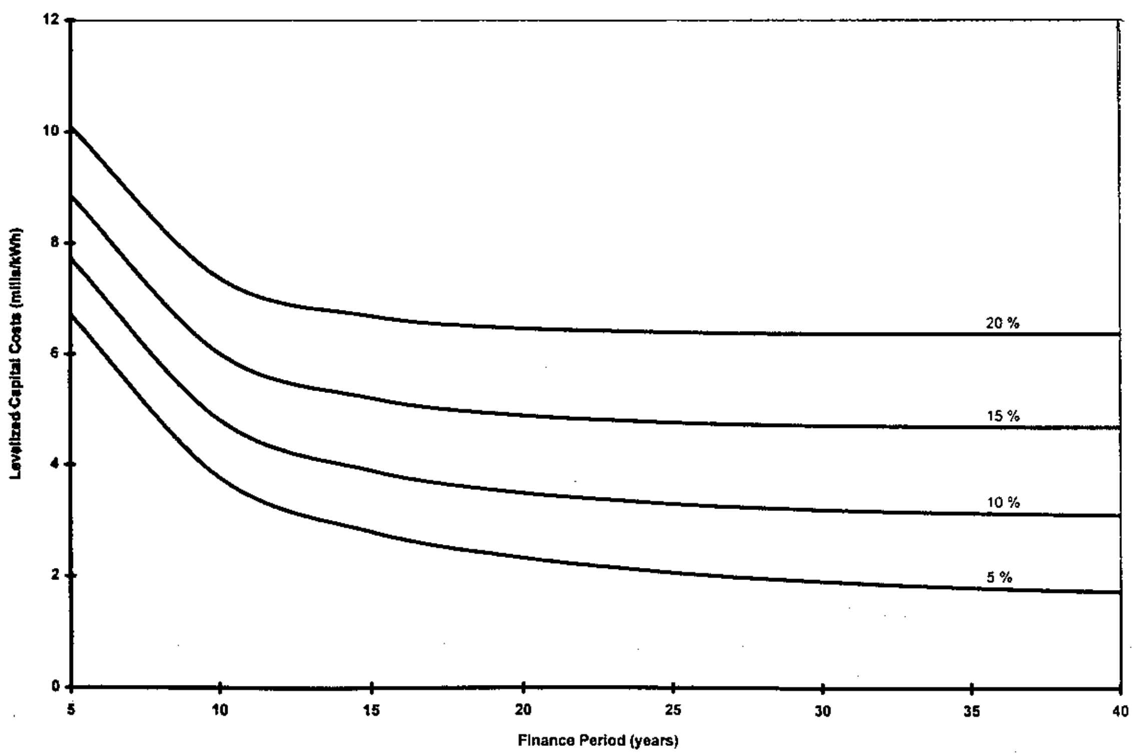

Figure 8 — Effect of Financing on SNRB Levelized Costs.

dramatically reduced the retrofit market for conventional SO_2 removal technologies[8]. However, individual units which require particulate and/or NO_x reductions, in addition to SO_2 reductions, may be good candidates for a SNRB retrofit. Improved boiler efficiency due to lower air heater exit temperatures allowed by a SNRB system can partially offset incremental operating costs. Units with existing "hot-side" electrostatic precipitators can more easily be retrofitted to a SNRB system, due to similarity in the arrangement of major equipment.

The near-term market in the U.S. will be mainly in the smaller new industrial sector. The primary driving force will be local environmental requirements. If the local restrictions are such that SO_2, NO_x and particulates are regulated to very low limits, thus requiring pollution abatement equipment for each of these pollutants, then SNRB will be an attractive, cost-effective option. The simplicity in operation of the SNRB over other technologies is a key reason why it could become the technology of choice.

Currently, many small industrial power plants are relying on the use of natural gas, thus avoiding the need for SO_2 and particulate control systems. When gas becomes less available and more expensive, the economics will change and coal could become the economic fuel choice. When this happens, the market for SNRB will accelerate rapidly. There are currently 2400 MW of small, indus-trial gas-fired boilers purchased annually. If 10% of these new capacity sales switch to coal in the future, the projected market for SNRB will be 240 MW, or approximately 20 units per year.

International Market

The differences between various international markets are very significant, and include cultural, political, and economic issues, as well as technical issues such as coal sources, experience base and demands for future power. A complete examination of any of these markets is beyond the scope of this paper; however, several general comments can be made regarding applicability of SNRB technology and future prospects.

The largest potential market for clean coal technologies in general is in Asia. In China alone, new coal-fired generating capacity is expanding at a rate of 10,000 MW per year. The installed base of particulate control equipment on coal-fired utility plants in Asia comprises largely electrostatic precipitators, with only a few relatively small baghouse installations. With this limited existing experience base of baghouse installations, some initial customer resistance is expected for SNRB and other fabric filter based technologies. Short-term opportunities will likely be limited to smaller industrial or municipal power plants, possibly with financial incentives offered by government agencies. After commercial demonstration of SNRB technology in the Asian market, long-term prospects are significant due to reliance on abundant coal reserves and tremendous pent-up demand for more power generation.

Latin America has also been identified as a large potential market for environmental technologies. However, due to extensive deposits of oil and development of Orimulsion™ supplies, coal-fired power is likely to be a relatively small portion of the power generation market in this region. Since SNRB was initially developed and successfully demonstrated for coal-fired application, short-term potential for this technology in Latin America appears somewhat limited. Potential future applicability of SNRB to oil-fired units and/or waste-to-energy plants would greatly increase market potential in Latin America, as well as other markets.

Central Europe, especially Poland and the Czech Republic, is currently an active market for retrofits of existing coal-fired power plants. Most of the existing utility-sized units have existing electrostatic precipitators, which in many cases are being upgraded at the same time that SO_2 removal equipment (typically limestone wet scrubbers) is being installed. Although the larger retrofit opportunities are expected to follow this existing trend, smaller industrial or municipal units, both new and retrofit, are candidates for SNRB technology.

Certainly potential future applications for SNRB technology exist anywhere that an integrated approach is desired for control of particulate, SO_2, and NO_X emissions. Most short-term applications are expected to be on smaller (<100MW) coal-fired plants.

SUMMARY

The SNRB system provides for high efficiency control of the primary emissions from coal-fired boilers. The system is capable of exceeding the SO_2 emission control performance of existing dry sorbent injection technologies. NO_x emission reduction comparable to commercial, conventional SCR systems has been demonstrated. In fact, emissions control at the SNRB demonstration exceeded the initial project goals. Additional work scope funded by the project co-sponsors has addressed several key questions for commercialization of the technology. Commercial-scale components used in the demonstration performed well and the component manufacturers demonstrated the ability to produce the components to commercial specifications. In all of the extended periods of continuous operation, the process achieved a high level of reliability, and the operability of the subsystems was clearly demonstrated.

The economic sensitivity analysis indicates the impact of various technical and economic factors on the SNRB process. In developing countries, where environmental compliance may be implemented in a phased approach, the SNRB installation can also be phased to reduce capital expenditures in the earlier stages, with reduced retrofit costs compared to conventional multi-pollutant removal systems.

ACKNOWLEDGEMENTS

The authors would like to thank the U.S. Department of Energy, the Ohio Coal Development Office and the Electric Power Research Institute for co-sponsoring the SNRB demonstration in conjunction with Babcock & Wilcox's Environmental Equipment Division. The cooperative efforts of 3M, Norton Chemical Process Products and Owens-Corning Fiberglas contributed greatly to the success of the field testing. The project is indebted to the Ohio Edison Company for providing the host site as well as invaluable counsel throughout the testing program.

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DISCLAIMER

ABSTRACT

CQE: Integrating Fuel Decisions

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David C. O'Connor, Electric Power Research Institute
G. Scott Stallard, Black & Veatch

ABB Combustion Engineering, Inc., (ABB-CE) and CQ Inc. completed a broad, comprehensive program to demonstrate the economic and environmental benefits of using higher quality U.S. coals for electrical power generation. The program was an essential extension and integration of R&D projects performed in the past under U.S. DOE and EPRI sponsorship and it expanded the available database of coal quality and power plant performance information. This expert system will permit utilities to purchase the lowest cost clean coals tailored to their specific requirements.

Based on common interest and mutual benefit the subject program was cosponsored by the U.S. DOE, EPRI, and eight U.S. coal-burning utilities. In addition to cosponsoring this program, EPRI contributed its background research, data, and computer models, and managed some other supporting contracts under the terms of a project agreement established between CQ Inc. and EPRI. The essential work of the proposed project was performed under separate contracts to CQ Inc. by Electric Power Technologies (EPT), Black & Veatch (B&V), ABB Combustion Engineering, Babcock & Wilcox (B&W), and Decision Focus, Inc.

During the program, 13 coal samples and one petroleum coke were examined to evaluate their raw coal characteristics, liberation potential and trace elements contents. Washability tests were conducted on the raw coals to determine their potential for beneficiation. From the initial group,

four coals were beneficiated to two levels (one "medium" and one "deep" cleaned) In CQ Inc.'s Coal Quality Development Center (CQDC) at Homer City, Pennsylvania. Samples of the coals produced at the CQDC and in commercial coal cleaning plants, as appropriate, were provided to ABB-CE and B&W for testing in the laboratory and in small (4-5 MBtu/hr) test rigs. ABB-CE evaluated the combustion effects of seven samples for tangentially-fired combustion systems and B&W performed a similar evaluation of two samples for cyclone combustors. Field testing in 200-900 MW coal-fired utility boilers was done at six power plant sites. A total of 13 tests were coordinated by EPT and the data were used to validate CQIM, developed for EPRI by B&V, and to develop new capabilities to supplement CQIM and produce the Coal Quality Expert (CQE).

CQE predicts the performance of various commercially available coals with regard to site-specific total plant performance, i.e., pulverization characteristics (mill wear, energy requirements), combustion performance (ignition stability, carbon burnout), fireside performance (slagging, fouling, ash erosion), and emissions (particulate, SO_2, NO_x). CQE combines results from the precedent CQIM and EPRI's Coal Cleaning Cost Model, NO_x formation model, and precipitator model to perform cost benefit analyses of improved coal quality on power plant performance.